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BEFORE THE ARIZONA CORPORATION COMMISSION

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LEA MÁRQUEZ PETERSON
ANNA TOVAR
KEVIN THOMPSON
NICK MYERS

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	DOCKET NO. E-01933A-22-0107 **ARIZONA SOLAR ENERGY INDUSTRIES ASSOCIATION'S AND SOLAR ENERGY INDUSTRIES ASSOCIATION'S SURREBUTTAL TESTIMONY**

SURREBUTTAL TESTIMONY OF KARL R. RÁBAGO AND KEVIN LUCAS

ACC - Docket Control - Received 3/6/2023 11:20 AM
ACC - Docket Control - Docketed 3/6/2023 11:38 AM

RESPECTFULLY SUBMITTED this 6th day of March, 2023.

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BEFORE THE ARIZONA CORPORATION COMMISSION

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IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	)	DOCKET NO. E-01933A-22-0107

SURREBUTTAL TESTIMONY OF

KARL R. RÁBAGO

ON BEHALF OF

ARIZONA SOLAR ENERGY INDUSTRIES ASSOCIATION ("ARISEIA")

AND SOLAR ENERGY INDUSTRIES ASSOCIATION ("SEIA")

ON ALLOWED RETURN ON EQUITY

AND COMMUNITY SOLAR PROGRAM PROPOSAL

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EXHIBITS

KRR-15: D. Rode & P. Fischbeck, *Regulated Equity Returns: A Puzzle,* Energy Policy 133 (2019), available at: https://www.sciencedirect.com/science/article/abs/pii/S0301421519304690.

KRR-16: K. D. Werner & S. Jarvis, *Rate of Return Regulation Revisited*, Energy Institute at Haas (2022), available at: https://haas.berkeley.edu/wp-content/uploads/WP329.pdf.

LIST OF FIGURES

[1] *Id.* at p. 9, Fig. 1(b).

I. INTRODUCTION & SUMMARY

Q1. Please state your name, business name and address, and role in this matter.

A1. My name is Karl R. Rábago. I am the principal of Rábago Energy LLC, a Colorado limited liability company, now located at 1350 Gaylord Street, Denver, Colorado. I appear here in my capacity as an expert witness on behalf of the Arizona Solar Energy Industries Association (ARISEIA) and the Solar Energy Industries Association (SEIA).

Q2. Are you the same Karl R. Rábago that previously filed direct testimony in this proceeding relating to Tucson Electric Power Company (Company or TEP) on the issues of the Company's allowed Return on Equity (ROE) and a Community Solar Program?

A2. Yes.

Q3. Has the Company filed rebuttal testimony relating to your direct testimony?

A3. Yes. However, Company witness Martha B. Pritz identifies me in her rebuttal testimony as "Karl Rábago," Company witness Anne E. Bulkley incorrectly identifies me as "Karl A. Rábago," and Company John D. Quackenbush incorrectly spells my name as "Karl Rabago."

Q4. **Please summarize your surrebuttal testimony.**

A4. In this testimony, I address two main issues. First, I point out that the rebuttal testimony filed by Company witnesses Martha B. Pritz, Anne E. Bulkley, and John D. Quackenbush does not actually rebut my direct testimony, in which I explain that the Company's transition to carbon-free generating resources will reduce the Company's financial risk and that therefore, an increase in the allowed ROE is not necessary. Second, I point out that Company witness Dallas Duke's testimony relating to a Community Solar program would be administratively inefficient and unreasonably delay the opportunity for TEP customers, including low-wealth customers, to subscribe to a Community Solar program.

II. RETURN ON EQUITY

Q5. Company witness Pritz asserts that your testimony "suggests the equity ratio be based on changes to the Company's cost of debt."[2] Does this assertion rebut your direct testimony?

A5. No. I did not suggest that the equity ratio be based on changes to the Company's cost of debt. Company witness Pritz's argument, and a similar one by Company witness Bulkley,[3] mischaracterize my testimony about capital structure and return on equity. Rather, I pointed out that the Company has, as it should have, reduced its cost of debt, and that "[i]t is unreasonable for the Company to increase the equity fraction in its capital structure" because such a change would obviate the benefits of lower debt costs and effectively assign to shareholders the benefits of lower debt costs by increasing reliance on more expensive equity.[4] This point remains unrebutted in the Company testimony.

Q6. Company witness Pritz also states that "[i]t is worrisome that Mr. Rábago says that because the Company does not show that it is experiencing financial impairment or having difficulty attracting capital, the proposed capital structure and return on equity are not justified."[5] Does this assertion rebut your direct testimony?

A6. No. Again, Company witness Pritz mischaracterizes my testimony referenced in her rebuttal testimony. In my direct testimony, I pointed out that the Company seeks to increase costs to customers by more than $33 million in annual revenue requirement through proposed changes in the ROE and equity ratio.[6] In my direct testimony, I point out that the Company's assertions that the *proposed changes* in the allowed ROE and capital structure are not justified by any deficiency in the Company's ability to attract capital or recover investments on a timely basis,

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[2] Pritz rebuttal at p. 2:13-14.
[3] Bulkley rebuttal at p. 7:19-22.
[4] Rábago ROE direct at p. 20:9-18.
[5] Pritz rebuttal at p. 5:16-18.
[6] Rábago ROE direct at p. 13, Table KRR-1.

or on an adverse regulatory climate.[7] The Company's proposed increases in the ROE and equity ratio remain unjustified.

Q7. Company witness Bulkley asserts that because your recommendation for an allowed ROE is at the "low end of the range of authorized ROEs over the past three years," when interest rates were lower than they are today, that recommendation is "too low to be considered reasonable."[8] Does the fact of today's higher interest rates rebut your testimony about why the Company's allowed ROE and equity ratio should not be increased?

A7. No. My testimony made several points that are unrebutted by the Company's witnesses. First, to the extent that the Company faces financial risk due to its continued excessive reliance on fossil fuels, that is not a risk that customers should pay for.[9] Second, the Company has an opportunity to securitize its stranded costs relating to coal generation, a cost relating to a poor investment strategy that it would seek to shift to customers and not its investors.[10] Third, the Company's rebuttal testimony fails to account for the financial cost and risk reduction benefits of a transition to fossil-free generation,[11] which can be assisted by increased reliance on non-utility generation, including community solar—which does not require equity capital—and which in turn justify *a reduction* in the allowed ROE and equity ratio. Fourth, the Company fails to account for the ways in which the Inflation Reduction Act (IRA) can provide cost and risk-reduction benefits for utilities making the transition away from fossil fuels and amplify the benefits of the transition.[12] None of these key points are addressed in the Company's rebuttal testimony and, therefore, remain unrebutted.

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[7] Rábago ROE direct at p. 15:6-16.
[8] Bulkley rebuttal at p. 6:21-26.
[9] Rábago ROE direct at p. 17:5-10.
[10] *Id.* at p. 17:10-13.
[11] Rábago ROE direct at p. 19:1-7, *citing* Bulkley supplemental testimony at p. 3:3-4.
[12] Rábago ROE direct at p. 18:6-20.

Q8. Company witness Bulkley alleges that your direct testimony discussed "prior authorized ROEs" but failed to "provide the necessary insight" regarding "forward-looking investor-required return," and that increased interest rates, which she broadly characterizes as "differences in market conditions," justifies the Company's ROE and equity ratio recommendations.[13] How do your respond?

A8. Company witness Bulkley mischaracterizes my direct testimony and ignores the points that I made regarding the future risk and cost reduction benefits of a transition away from fossil fuels, especially in an environment in which the IRA is operational. Company witness Bulkley's exclusive reliance on rising interest rates as a justification for an increase in allowed ROE and in greater reliance on more-expensive ROE through an increased equity ratio ignores the forward-looking and offsetting factors that I identified. Again, the Company's proposals would add $33 million per year to customer costs and Company profits, without justification.

Q9. Company witness Bulkley also asserts that rising interest rates mean that your proposed ROE of 9.15 percent is unreasonable because your proposal would not maintain historical risk premiums that Company shareholders have enjoyed in the past.[14] Do you agree?

A9. No. Company witness Bulkley correctly observes that the risk premium—the level of allowed ROEs above the risk-free cost of capital—has been much higher than it would be under current bond rates and my proposed ROE level of 9.15 percent. What is missing in Company witness Bulkley's testimony is any justification for the unreasonably high-risk premia utilities have enjoyed in recent years. Further, Company witness Bulkley's testimony obscures this historical reality by using charts that rely on different scales for the left and right vertical axes.[15]

Q10. What does a more objective analysis of historical risk premia demonstrate?

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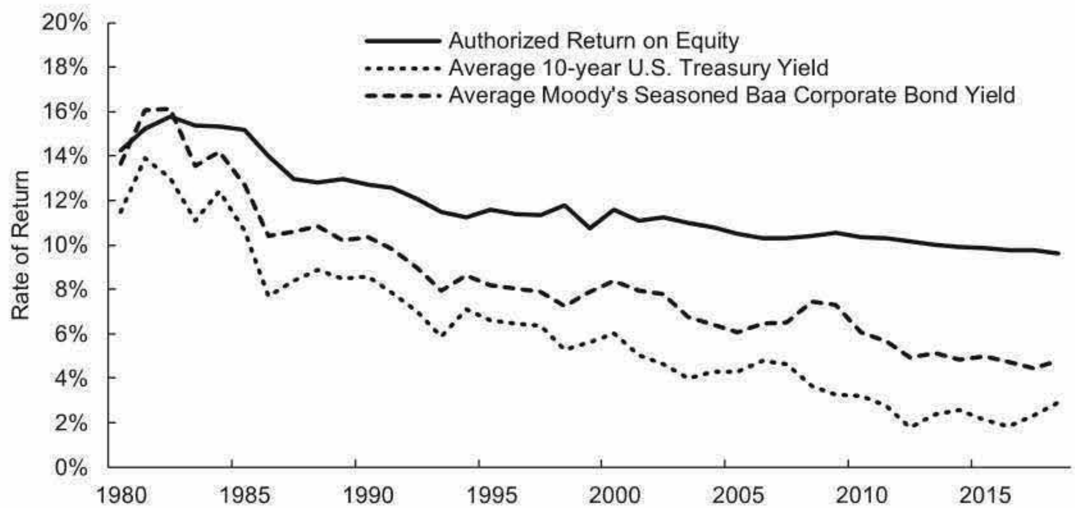
[13] Bulkley rebuttal at p. 8:6-14.
[14] Bulkley rebuttal at pp. 10:1 through 15:3.
[15] *Id.* at p. 11, Fig. 1; p. 14, Fig. 2.

A10. The excessive and unjustified trend in utility ROE risk premia has been documented in academic literature. David C. Rode and Paul S. Fischbeck looked at forty years of allowed ROEs and determined that they were excessive and not financially or economically justified.[16] This historical data is reproduced in Figure KRR-15, below.[17]

Figure KRR-1: Annual Average Authorized ROE vs. U.S. Treasury and Investment Grade Corporate Bond Rates



Q11. Does more recent data confirm the trends identified in the Rode & Fischbeck analysis?

A11. Yes, a 2022 paper from Karl Dunkle Werner and Stephen Jarvis tracks data through 2020 and measures historical ROEs against several financial indices. This analysis also shows that rote reliance on historical risk premia is unjustified and unreasonable.[18]

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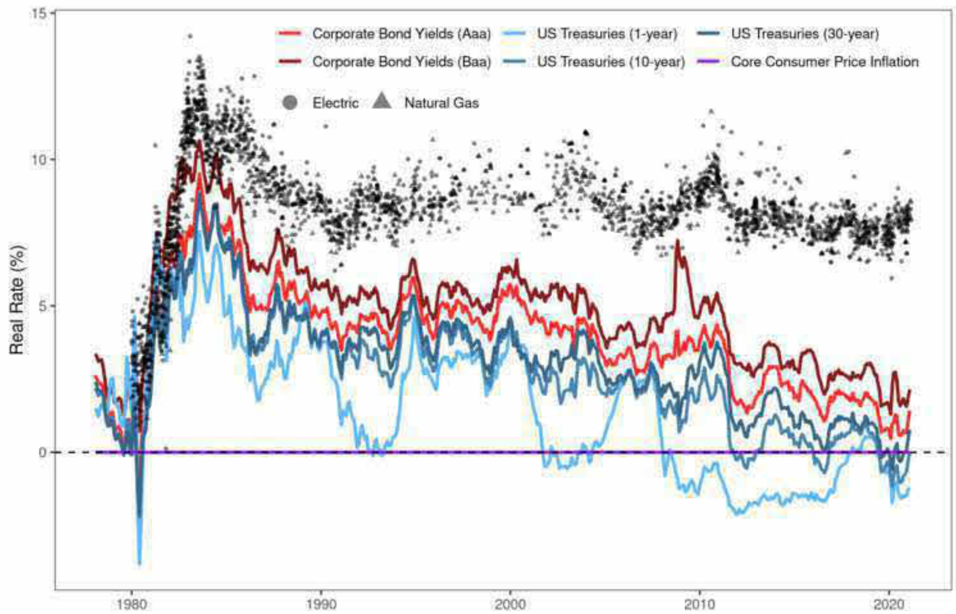
[16] D. Rode & P. Fischbeck, *Regulated Equity Returns: A Puzzle,* Energy Policy 133 (2019), available at: https://www.sciencedirect.com/science/article/abs/pii/S0301421519304690 attached as KRR-15.
[17] *Id.* at p. 5, Fig. 4.
[18] K. D. Werner & S. Jarvis, Rate of Return Regulation Revisited, Energy Institute at Haas (2022), available at: https://haas.berkeley.edu/wp-content/uploads/WP329.pdf, attached as KRR-16.

Figure KRR-2: Return on Equity and Financial Indicators (Real \$)[19]



Q12. Please summarize your surrebuttal testimony relating to ROE.

A12. I maintain my recommendation to the Commission that an allowed ROE of 9.15 percent and an equity ratio of 52.95% are reasonable in light of all the relevant factors. The Company witnesses have failed to provide any rebuttal to my testimony regarding the factors that justify a lower ROE and equity ratio than proposed by the Company.

III. COMMUNITY SOLAR

Q13. What is the Company rebuttal testimony regarding your Community Solar program proposal?

A13. Company witness Dallas Dukes recommends that the Commission reject my proposal that the Company be ordered to establish a Community Solar program. Company witness Dukes notes that the Commission evidentiary hearing in Docket No. E-99999A-22-0291 will address several Community Solar issues.[20] He also takes issue with the recommendation for setting the

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[19] *Id.* at p. 9, Fig. 1(b).

[20] Dukes rebuttal at pp. 7:16 through 8:18.

Community Solar credit based on the Resource Comparison Proxy (RCP) export rate.[21] He raises undocumented "significant concerns" about consumer protection issues,[22] and reliability,[23] and based on an unsupported argument that utility-scale and local distributed solar have the same value, appears to argue that Community Solar subscribers should not be credited for Community Solar production at anything higher than a wholesale rate.[24] Mr. Dukes also asserts a Company position that monopolized solar programs are an equivalent option for customers as those provided by non-utility competitive service providers.[25]

Q14. Please summarize your response to the Company.

A14. I do not agree that the Commission should reject the Community Solar proposal, and I maintain my original recommendation that the Commission direct the Company to develop a program proposal consistent with the guidance filed in my direct testimony. My greatest concerns with the Company position are that: (1) the Company must start now to develop the program in order to not lose time in providing customers with access to the many benefits of Community Solar,[26] (2) allowing the Company to offer monopoly-based solar programs while delaying competitive options raises unfair competition concerns, and (3) a Community Solar program will create costs for the Company that should be addressed in a rate proceeding and the timing of future proceedings is unknown. The Company's recommended rejection will create delay and administrative complexity that can be avoided by ordering the development of the program in this proceeding.

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[21] *Id.* at p. 9:3-22.
[22] *Id.* at p. 10:1-7.
[23] *Id.* at p. 10:9-15.
[24] *Id.* at pp. 10:17 through 11:3.
[25] *Id.* at pp. 11:5 through 11:3.
[26] Rábago Rate Design direct at pp. 9:5 through 11:14.

Q15. Company witness Dukes states that all matters regarding Community Solar should be evaluated through an evidentiary hearing.[27] Do you agree?

A15. I have put forward a proposal that includes all components identified in Decision No. 78784, including the items to be addressed both with and without an evidentiary hearing and, therefore, agree that all of them can be evaluated within this rate case, which is an evidentiary hearing.

Q16. Company witness Dukes asserts concerns over consumer protections in Community Solar programs.[28] How do you respond?

A16. The Company has not identified which consumer protection concerns have not been addressed adequately in the proposal that I submitted. Based on my recommendation, the Company would have an additional 180 days to submit its own Community Solar proposal. Since the Company has been aware of and participating in this issue in front of the Commission for nearly a year already, that should be ample time to address the ill-defined concerns raised in its rebuttal testimony.

Q17. Company witness Dukes asserts concerns over grid reliability stemming from Community Solar.[29] How do you respond?

A17. Community solar programs already exist in twenty-two (22) other states and the District of Columbia (DC). The Commission need not start from scratch. All of these other jurisdictions have been able to address the concerns raised by the Company. Further, Community Solar is equivalent to rooftop solar for customers that cannot for whatever reason install solar on their own roofs. Rooftop solar is well-established in Arizona, is accounted for reliably on the grid by all of the state's utilities, and is must-take. The Company has asserted no identifiable reasons

[27] Dukes rebuttal at pp. 8:16-18.
[28] Dukes rebuttal at pp. 10:1-7.
[29] Dukes rebuttal at pp. 10:9 through 11:3.

to differentiate Community Solar or deviate from the practices working in half the country already.

Q18. Company witness Dukes asserts that the Commission needs to redo the Value of Solar docket for Community Solar.[30] How do you respond?

A18. The purpose of the Value of Solar Docket was to determine a fair value for energy exported from distributed solar, creating a new rate from scratch. Community solar is at least as valuable as rooftop solar and it can provide other benefits. Because I am proposing to use the RCP, which the Commission has already determined is fair compensation for exported distributed solar, there is no need for another multi-stage proceeding. That argument is simply a tactic of delay.

Q19. Are there other examples of the Company trying to delay proceedings in a rate case?

Q19. Yes, in the Company's last rate case it sought to delay addressing coal community transition (CCT) issues. That resulted in a bifurcated proceeding with a generic docket and a phase 2 of the 2019 rate case. The docket was ongoing for two years, failed to proceed, and then was moved into this pending rate case, resulting in a three-year delay. The Commission should not repeat that process here. Further, the Company makes the same argument regarding wholly unrelated testimony in this rate case presented by AriSEIA/SEIA witness Lucas.[31] A fair reading of the Company's testimony is that any other place is a better place to discuss numerous issues that are directly applicable to rates.

Q20. Is a rate case the appropriate place to address Community Solar?

A20. Company witness Dukes paradoxically states that all the items related to Community Solar should be addressed in an evidentiary hearing and that they should be "specific to each utility separately" while simultaneously arguing that their rate case is not the appropriate place to

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[30] Dukes rebuttal at pp. 12:1-11.
[31] Dukes rebuttal at pp. 15:9 through 16:5.

address it.[32] First, a rate case is an evidentiary hearing. Second, a rate case is specific to each utility separately. Third, as a former utility commissioner, I am very familiar with appropriate subject matter to be included within rate cases. Rate cases are utilized to establish or address rates, contracts, practices, rules, regulations, or other matters that the Commission finds just and reasonable. Community Solar would create a new program with an established bill credit rate that directly impacts subscribers' utility bills. Further, over the course of the working group, some participants (now intervenors) asserted the rate case was the most appropriate place to address Community Solar.[33]

Q21. Company witness Dukes asserts that the Community Solar issue has to date been applicable solely to APS.[34] How do you respond?

A21. The Company admits they have been participating in Community Solar proceedings in front of the Commission "over the past year."[35] Decision No. 78583, which created the Community Solar working group, specifically included "all electric public service corporations."[36] The Company was included in filings in the Community Solar generic docket several times, commencing at least as early as May 23, 2022.[37] The working group commenced on June 9, 2022 and the Company attended.[38] The Company met with AriSEIA and other stakeholders

[32] Dukes rebuttal at pp. 8:16-18.
[33] RUCO Comments to Staff's Report filed Nov. 4, 2022 in Docket No. E-00000A-22-0103, *available here:* https://docket.images.azcc.gov/E000022210.pdf?i=1676578845697, ("RUCO continues to recommend that Community Solar be addressed in a rate case,"). Staff Proposed Amendment filed on Nov. 7, 2022 in Docket No. E-00000A-22-0103, *available here* https://docket.images.azcc.gov/E000022257.pdf?i=1676578845697, ("APS has a pending rate case, Tucson Electric Power Company has a pending rate case, and UNS Electric, Inc. is expected to file a rate case later in November. Staff recommends that the issue of community solar be addressed in the evidentiary hearings to be held in those dockets,").
[34] Dukes rebuttal at pp. 7:8-14.
[35] Dukes rebuttal at pp. 7:9.
[36] Decision No. 78583, Docket No. E-01345A-21-0240, May 27, 2022, pp. 10:15-16, *available here*: https://docket.images.azcc.gov/0000206888.pdf?i=1677301659830.
[37] Staff Memorandum, Docket No. E-00000A-22-0103, May 23, 3033, *available here*: https://docket.images.azcc.gov/E000019380.pdf?i=1677301924247; Commissioner Marquez Peterson correspondence, Docket No. E-00000A-22-0103, May 23, 2022, *available here*: https://docket.images.azcc.gov/E000019360.pdf?i=1677301924247.
[38] Staff Memorandum, Docket No. E-00000A-22-0103, June 1, 2022, *available here*: https://docket.images.azcc.gov/E000019510.pdf?i=1677301924247.

regarding Community Solar in July of 2022. The working group met several times through the summer of 2022 and the matter of Community Solar pertinent to the Company's pending rate case was discussed at the November open meeting. Therefore, the Company has been well-apprised of Community Solar's progress in Arizona, has had ample time to consider how Community Solar would be applied in its service territory, and has known since last year that the Commission intended to create a state-wide program. The modifications I have proposed to our original proposal in APS service territory are more than sufficient for the Company and, again, the Company would have an additional 180 days to propose its own program.

Q22. Company witness Dukes asserts the RCP is not applicable to Community Solar.[39] How do you respond?

A22. I see no reason that the RCP cannot be applied to set a generation credit rate for Community Solar. To the extent that there are issues of adaptation or modification because of the differences between Community Solar and on-site or rooftop solar, the Company should raise them and address them in the 180-day period that I recommend.

Q23. Please summarize your Community Solar testimony in response to the Company's rebuttal testimony.

A23. The Company seeks to delay my proposal for a Community Solar program in its service territory while also arguing Community Solar should be addressed in an evidentiary hearing unique to it. This rate case is an evidentiary hearing unique to the Company and it has been on notice for a year that this was a matter that would need to be addressed in its service territory imminently. The Company's attempt to kick the can down the road, resulting in delay, inefficiencies, and wasted Commission time and resources should be rejected. Moreover, the Company's approach would be to allow it, as a monopoly, to continue as the sole provider of

[39] Dukes rebuttal at pp. 9:3-22.

off-site solar services for customers, another inefficient outcome that would stifle market competition and growth.

Q.24 Does this conclude your surrebuttal testimony?

A24. Yes.

EXHIBIT KRR-15

Energy Policy 133 (2019) 110891

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Regulated equity returns: A puzzle

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ARTICLE INFO

Keywords:
Discount rate
Electric utility
Rate of return regulation
Valuation

ABSTRACT

Based on a database of U.S. electric utility rate cases spanning nearly four decades, the returns on equity authorized by regulators have exhibited a large and growing premium over the riskless rate of return. This growing premium does not appear to be explained by traditional asset-pricing models, often in direct contrast to regulators' stated intent. We suggest possible alternative explanations drawn from finance, public policy, public choice, and the behavioral economics literature. However, absent some normative justification for this premium, it would appear that regulators are authorizing excessive returns on equity to utility investors and that these excess returns translate into tangible profits for utility firms.

1. Introduction

In economics, the equity-premium puzzle refers to the empirical phenomenon that returns on a diversified equity portfolio have exceeded the riskless rate of return on average by more than can be explained by traditional models of compensation for bearing risk. Since Mehra and Prescott's (1985) initial paper on the subject, a large body of research has attempted to explain away the puzzle, but without much success (Mehra and Prescott, 2003). The most likely explanations for the premium appear to reside outside of classical equilibrium models. We call the reader's attention to the Mehra-Prescott puzzle as a means of introducing our instant problem, of which it may be considered an applied case. Simply put: why are the equity returns authorized by electric utility regulators so high, given that riskless rates are so low?

Our scope is as follows. We employ a much larger dataset than has previously been examined in the literature and seek to explain the rates of return *authorized* by state electric utility regulators. We investigate the extent to which the actual returns authorized can be explained by the Capital Asset Pricing Model (CAPM), which regulators (and others) purport to use. We also examine whether the CAPM is capable of explaining the clear trend of rising risk premiums present over the last four decades in electric utility rate cases.

While previous studies have investigated rates of return for regulated electric utilities, the majority of this work has either examined *actual* rates of return to utility stockholders, relied on very limited samples of rate cases, or tested a variety of hypotheses connecting utility earnings to various structural and institutional factors. Table 1 summarizes the previous literature most similar to our study. By contrast, our study employs a far larger sample of rate cases (1,596) than previously examined in the literature. In addition, our focus on authorized rates of return highlights the impact of regulatory rate-setting on consumers, as opposed to stockholders, to the extent that authorized rates are used to set utility revenue requirements, while earned returns accrue to stockholders. This setting also enables us to analyze rate-setting in the context of regulatory decision-making. Actual rates of return earned by utilities can differ from the rates of return authorized by regulators due to factors such as the impact of weather on demand, but primarily due to the operational performance of a utility, including its ability to operate efficiently and control costs to those approved by regulators.

This regulated equity return puzzle is important not just from a theoretical asset-pricing perspective, but also for very practical reasons. The database used in this study reflects more than $3.3 trillion (in 2018 dollars) in cumulative rate-base exposure.[1] An error or bias of merely one percentage point in the allowed return would imply tens of billions of dollars in additional cost for ratepayers in the form of higher retail power prices and could play a profound role in the allocation of investment capital. Coupled with utilities' tendencies toward excessive capital accumulation under rate regulation (Averch and Johnson, 1962; Spann, 1974; Courville, 1974; Hayashi and Trapani, 1976; Vitaliano

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[1] This figure reflects the simple cumulative sum of authorized rate bases across all cases. Because rate-base decisions may remain in place for several years, this sum most likely underestimates the actual figure, which should be the authorized rate base in each year examined, whether or not a new case was decided. We cite this figure merely as evidence of the substantial magnitude of the costs at stake.

https://doi.org/10.1016/j.enpol.2019.110891
Received 22 January 2019; Received in revised form 18 July 2019; Accepted 19 July 2019
Available online 25 July 2019
0301-4215/

Table 1
Previous studies of the determinants of electric utility rates of return.

Study	Sample	Description
Joskow (1972)	20 cases in New York between 1960 and 1970	Only capital markets parameter included was cost of debt. Focused on the requested rate of return.
Joskow (1974)	174 cases between 1958 and 1972	No CAPM parameters tested. Regulators tended to ignoring overearning as long as prices were falling.
Hagerman and Ratchford (1978)	79 survey responses from utilities about their last rate case	Used authorized rates. Found positive coefficients related to beta and the debt/equity ratio.
Roberts et al. (1978)	59 cases from 4 Florida utilities between 1960 and 1976	No CAPM parameters tested. Only structural factors examined.
Roll and Ross (1983)	Utility stock returns between 1925 and 1980	No authorized returns used. CAPM underestimates returns relative to the APT.
Pettway and Jordan (1987)	58 electric service companies between 1969 and 1976	Used stockholder returns only.
Binder and Norton (1999)	92 firms	Used stockholder returns to estimate beta. Suggested that regulation causes cash flow "buffering" and that firms may be underearning.
PJM Interconnection (2016)	22 regulated firms between 2000 and 2015	Examined stockholder returns and found regulated firms had positive alpha.
Haug and Wieshammer (2019)	N/A	Regulators in continental Europe "uniformly adopt the [CAPM]" and courts have ruled that the authorized rates are too low. The opposite finding to our study.

and Stella, 2009), the magnitude of the problem makes it incumbent on the industry and regulators to get it right.

There are also policy implications for market design and regulation. A recent PJM Interconnection (2016) study compared and contrasted entry and exit decisions in competitive and regulated markets to evaluate the efficiency of competitive markets for power. One finding that emerged from the study was that regulated utilities appeared to be "overearning" and had generated positive alpha, while competitive firms had not generated positive alpha.[2] Although the study used a limited time window of rate case data and focused on utility stock returns, not returns authorized by regulators, its findings are consistent with those we explore in more detail here.

As an old joke goes, an economist is someone who sees something work in practice and asks whether it can work in theory. Undoubtedly, the utility sector has been successful in attracting capital over the past four decades. We cannot necessarily say, however, that had returns been consistent with the dominant theoretical model used (and thus lower), this would still have been the case. Accordingly, this article also raises the question of whether our theoretical models of required return and asset pricing must be refined. Or, at the very least, whether there are important considerations that must be accounted for in the application of those models to the regulated electric utility industry.

In this article, therefore, we examine the historical data on authorized rates of return on equity in U.S. electric utility rate cases. We compare these rates of return to several conventional benchmarks and the classical theoretical asset-pricing model. We demonstrate that the spread between authorized equity returns (and also earned equity returns) and the riskless rate has grown steadily over time. We investigate whether this growing spread can be explained by classical asset-pricing parameters and conclude that it cannot. We then evaluate possible explanations outside of classical finance to suggest fruitful paths for future research. Specifically, we investigate whether the addition of variables for commission selection and case adjudication contribute explanatory power, in line with existing theories in the pubic choice literature. We conclude with a discussion of the policy implications of the observed premiums and how regulatory rate-setting could be adjusted to mitigate higher premiums.

Section 2 reviews the legal, regulatory, and financial foundations of rate of return determination for utilities. Section 3 describes the data used in our analysis and defines the risk premium on which our analysis is based. Section 4 presents the results of our analysis and outlines the various factors explored, including both classical financial factors and factors outside of the classical paradigm. Section 5 highlights the policy implications of our research, suggests potential mitigating strategies, and concludes.

2. Regulated equity returns and the Capital Asset Pricing Model

At the outset, let us make clear that we are addressing only *regulated* rates of return on equity in this article. We draw no conclusions or inferences about the behavior of returns on non-regulated assets. Our focus is limited to regulated returns because in such cases it is regulators who are tasked with standing in for the discipline of a competitive market and ensuring that returns are just and reasonable. For more than a century, U.S. courts have ruled consistently in support of this objective, while recognizing that achieving it requires consideration of numerous factors that are subject to change over time. The task set to regulators, then, is to approximate what a competitive market would provide, *if one existed.*

Mindful of this mandate, two U.S. Supreme Court decisions are commonly thought to provide the conceptual foundation for utility rate-of-return regulation. In *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia* (262 U.S. 679 (1923)), the Court identified eight factors that were to be considered in determining a fair rate of return, ruling that "[t]he return should be reasonable, sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economic management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties." This position was made more concrete in *Federal Power Commission v. Hope Natural Gas Company* (320 U.S. 591 (1944)), wherein the Court ruled that the "return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."

In both *Bluefield* and *Hope*, the Court sought to balance the need for utilities to attract capital sufficient to discharge their duties with the need for regulators to protect ratepayers from what would otherwise be rent-seeking monopolists. These efforts in determining "just and reasonable" returns received significant assistance in the 1960s when groundbreaking advances in asset-pricing theory were made in finance. Specifically, the development of the Capital Asset Pricing Model (CAPM) (Sharpe, 1964; Lintner, 1965; Mossin, 1966) provided a rigorous framework within which the question of the appropriate rate of return could be addressed in an objective fashion. The security market line representation of the CAPM [1] set out the equilibrium rate of return on equity, r_E, as the sum of the rate of return on a riskless asset,

[2] In asset pricing models, positive alpha is evidence of non-equilibrium returns, meaning that investors are receiving compensation in excess of what would be required for bearing the risks they have assumed.

r_f, and a premium related to the level of risk being assumed that was defined in relation (through the factor β) to the expected excess rate of return on the overall market for capital, r_m.

$$r_E = r_f + \beta(r_m - r_f) \tag{1}$$

It is outside of the scope of this paper to delve too deeply into the foundations of asset pricing. We note, also, that the CAPM methodology is not the sole candidate for rate-of-return determination in utility rate cases. Morin (2006, p. 13) identifies four main approaches used in the determination of the "fair return to the equity holder of a public utility's common stock," of which the CAPM is but one.[3] Nevertheless, the concept of the appropriate rate of return on equity being a combination of a riskless rate of return and a premium for risk-bearing has since become widely accepted as a means of determining the appropriate authorized return on equity in state-level utility rate cases (Phillips, 1993, pp. 394–400). In contrast, the Federal Energy Regulatory Commission relies exclusively on the DCF approach, which is also common with natural gas utilities. For electric utilities, however, the CAPM in particular is seen as the "preferred" (Myers, 1972; Roll and Ross, 1983, p.22) and "most widely used" (Villadsen et al., 2017, p. 51) method in regulatory proceedings. Multi-factor approaches such as Arbitrage Pricing Theory (APT) (Ross, 1976) and the Fama and French (1993) framework are used with significantly less frequency in practice (Villadsen et al., 2017, p. 206). In other words, our focus on the CAPM is not solely because of its perceived normative status, but also because it is the method most regulators *say they are using.*

In *Hope,* however, the Court also advocated the "end results doctrine," acknowledging that regulatory methods were (legally) immaterial so long as the end result was reasonable to the consumer and investor. In other words, there was no single formula for determining rates. A typical example of the latitude granted by the doctrine is found in Pennsylvania Public Utility Commission (2016, p. 17): "The Commission determines the [return on equity] based on the range of reasonableness from the DCF barometer group data, CAPM data, recent [returns on equity] adjudicated by the Commission, and **informed judgment** [emphasis added]." Rate determination in practice is often not simply a matter of arithmetic; rather, it is an act of judgment performed by regulators. As a result, our investigation examines not just the relation of authorized rates to those implied by the CAPM, but also the potential for that relationship to be influenced by regulator judgment.

Before we turn to the data, however, let us dispense with an alternate formulation of the underlying question. In questioning the size of the premium and why equity returns are so high, one might also ask instead why the riskless rate is so low. Indeed, Mehra and Prescott (1985) ask this very question, before dismissing it on theoretical grounds. We revisit this question in light of recent data and ask whether the premium during the period in question is more a function of riskless rates being forced down by the Federal Reserve's intervention, than of equity premiums increasing (since the manifest intent of quantitative easing was to lower riskless rates).[4] Our historical data, as Section 3 indicates, do not support that hypothesis. The premium growth has persisted since the beginning of our data series in 1980 and has persisted across a variety of monetary and fiscal policy regimes.

3. Regulated electric utility returns on equity, 1980–2018

3.1. Historical authorized return on equity data

The data used in this study were collected and maintained by Regulatory Research Associates (RRA), a unit of S&P Global. The RRA database is comprehensive. It contains every electric utility rate case in the United States since 1980 in which the utility has requested a rate change of at least \$5 million or a regulator has authorized a rate change of at least \$3 million. Our study comprises the period from 1980 through 2018. Table 2 illustrates the bridge from the RRA rate-case population to the rate-case sample used in our analyses. We examined the returns on equity authorized by the regulatory agencies, *not* the returns requested by the utilities.[5] The sample we use in this paper contains 79% of the RRA universe, but 97% of the rate cases in which a rate of return on equity was authorized by a state regulator.

Nearly all fifty states and Washington D.C. are represented in the data set.[6] Thirty-two electric utility rate cases satisfying the qualifications listed above were filed in the average state over the past thirty-eight years, with the most being filed in Wisconsin (120) and the fewest being filed in Tennessee (3), Alaska (2), and Alabama (1). The frequency of filing in a state does not appear to have any relationship to premium growth. The average risk premium has grown in both the ten states that completed the most rate cases and the ten states that completed the fewest rate cases and has grown at very similar rates (see Fig. 1). In fact, as Fig. 2 illustrates, the general trend across all states is similar.

In the early 1980s there were over 100 rate cases filed each year. By the late 1990s, in the midst of widespread deregulation of the electric power industry, the number of filings reached its lowest point (with six in 1999). Since then, filing frequency has increased to an average of forty-eight per year over the last three years (see Fig. 3). The decline in rate case activity in many instances was the direct result of rate moratoria related to the transition to competitive markets in the late 1990s, as well as to moratorium-like concessions made to regulators related to merger approvals over the last decade. Many of these moratoria will expire over the next two years, suggesting a new increase in rate case activity is likely. Finally, no individual utility had an outsized influence on the sample. One hundred forty-four different companies filed rate cases, but many have since merged or otherwise stopped filing.[7] The average firm filed eleven rate cases in our sample. Within our sample the most frequently-filing entity was PacifiCorp, which filed seventy-three rate cases, or less than 5% of the sample.

3.2. Calculating the regulated equity premium

Regulated equity returns are generally equal to the sum of the riskless rate of return and a premium for risk-bearing. In the CAPM, the premium for risk-bearing is given by $\beta(r_m - r_f)$, where β is the utility's

[3] The other three approaches identified by Morin (2006) are: Risk Premium (which is an attempt to estimate empirically what the CAPM derives theoretically), Discounted Cash Flows (or "DCF," which is a dividend capitalization model), and Comparable Earnings (which is an empirical approach to deriving cost of capital from market comparables based on *Hope*).

[4] This has also been an ongoing issue of contention in recent regulatory proceedings. In Opinion 531-B (Federal Energy Regulatory Commission, March 3, 2015, 150 FERC 61,165), the Federal Energy Regulatory Commission (FERC) found that "anomalous capital market conditions" caused the traditional discount rate determination methods not to satisfy the *Hope* and *Bluefield* requirements (150 FERC 61,165 at 7). But in a related decision only eighteen months later (Federal Energy Regulatory Commission, September 20, 2016, 156 FERC 61,198), FERC acknowledged that expert witnesses disagreed as to whether any market conditions were, in fact, "anomalous" (156 FERC 61,198 at 10).

[5] To be clear, we refer to the rates set by regulators as the "authorized" rates. These may be contrasted with utilities' "requested" rates and also with the "earned" rates of return actually realized by utilities. Regulatory *authorization* of a rate is not a guarantee that a utility will actually *earn* such a rate. We address this issue in further detail in Section 4.5.

[6] Only Nebraska did not have a reported rate case meeting the parameters of the data set. Nebraska is unique in that it is the only state served entirely by consumer-owned entities (e.g., cooperatives, municipal power districts) and therefore absent a profit motive it does not have the same adversarial regulatory system as all other states.

[7] The level of analysis is at the regulated utility level. We recognize that many holding companies have multiple ring-fenced regulated utility subsidiaries.

Table 2
Bridge illustrating how our sample is constructed from the RRA electric utility rate case population data.

Number of cases	Percent of cases	Description
2033	100.0%	All electric utility rate cases 1980–2018 in which utility has requested a rate change of at least $5 million or a regulator has authorized a rate change of at least $3 million.
−19	−0.9%	Rate cases with final adjudication (i.e., fully-litigated or settled) still pending as of December 31, 2018, are excluded
−369	−18.2%	Rate cases with no return on equity determination are excluded
−30	−1.5%	Rate cases with no capital structure determination are excluded
−19	−0.9%	Rate cases with authorized rates lower than the then-prevailing riskless rate are excluded
1596	79.0%	Rate cases used in our analysis

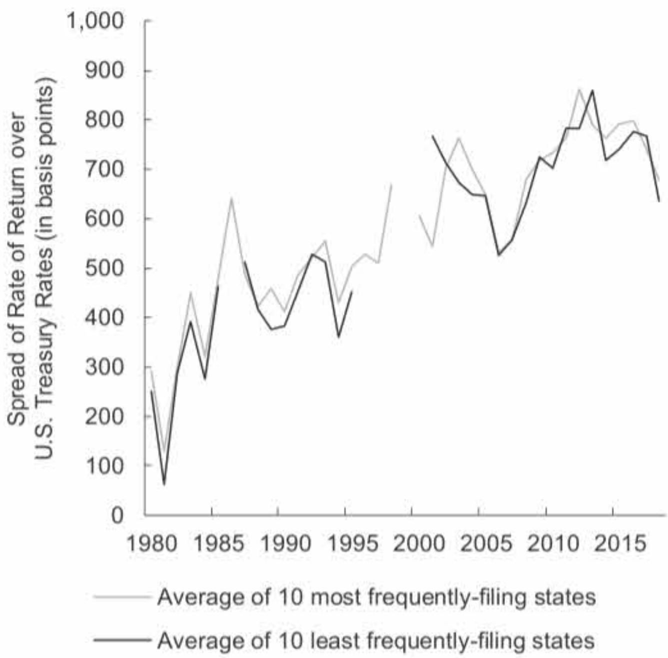

Fig. 1. Risk-premium growth by frequency of case filing. Gaps in the series reflect years in which no rate cases were filed for the subject group. The risk premium is calculated as $r_E - r_f$, or the excess of the authorized return on equity over the then-current riskless rate.

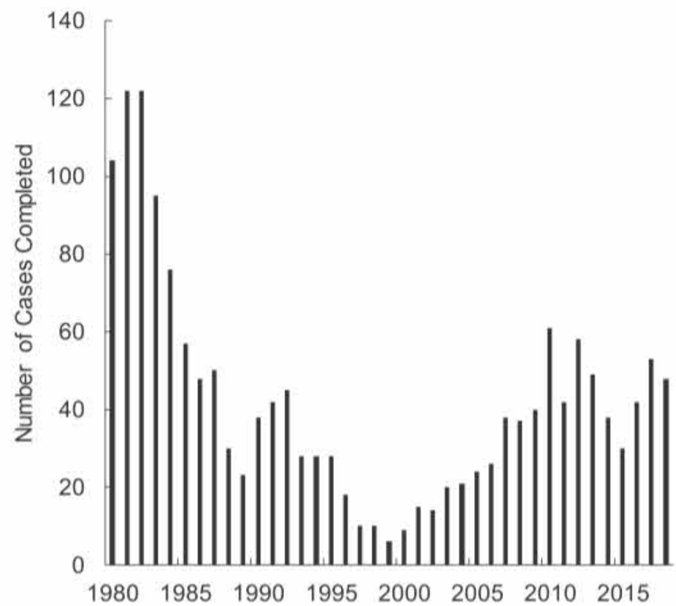

Fig. 3. Number of electric utility rate cases finalized by year.

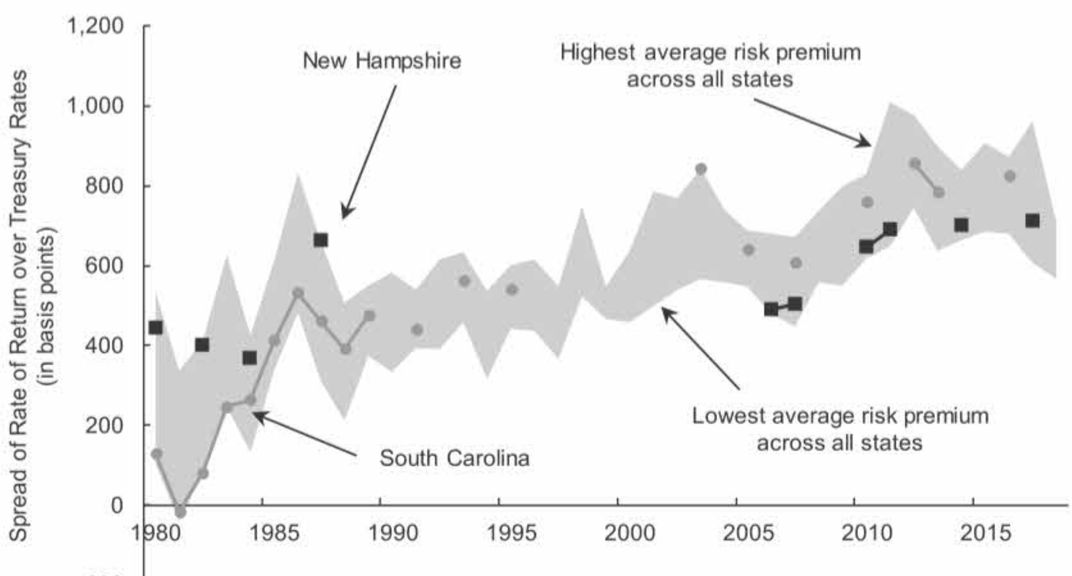

Fig. 2. Range of risk-premium growth across states. States with highest (New Hampshire) and lowest (South Carolina) rates of risk-premium growth over the period (among states with at least five rate cases) are highlighted.

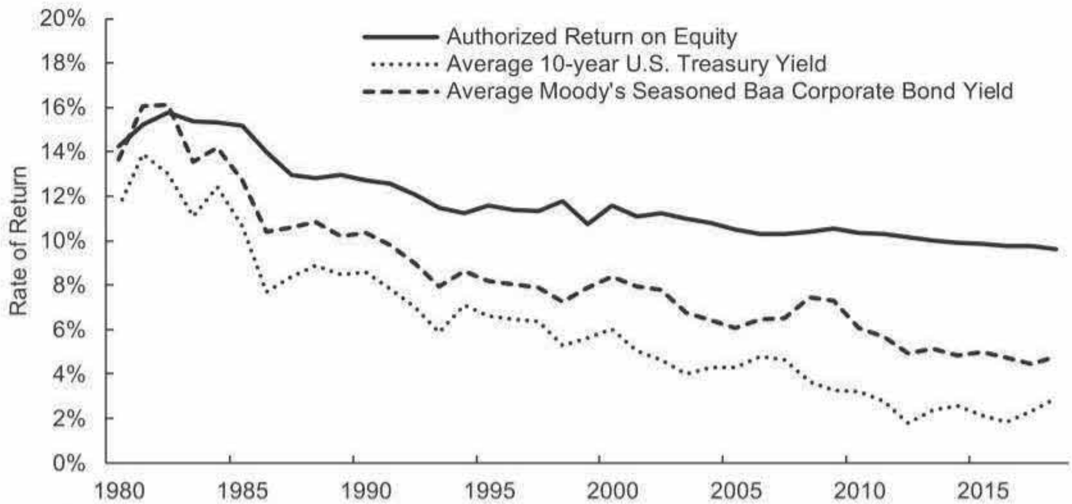

Fig. 4. Annual average authorized return on equity vs. U.S. Treasury and investment grade corporate bond rates.

equity beta. Rearranging the security market line equation [1], we define the regulated equity premium as $r_E - r_f = \beta(r_m - r_f)$. Presented thus, we first note that the existence of a (positive) regulated equity premium is not, by itself, evidence of irrational investor behavior or model failure. Neither is the existence of a growing regulated equity premium. We take no position here on what the "correct" premium should be in any instance. Rather, we shall be content in this article simply to determine whether or not the behavior of the risk premium in practice is consistent with financial theory.

On average, the authorized return on equity is 5.1% (standard deviation = 2.2%) higher than the riskless rate. Fig. 4 illustrates the average authorized return on equity over the period against the average annual riskless rate and investment-grade corporate bond rate.[8] For avoidance of doubt, we note that only the U.S. Treasury note rate should be considered the riskless rate. We include corporate bond rates solely to assess whether the trend in riskless rates is materially different from the trend in risky debt.

While the regulated equity premium has averaged 510 basis points across the entire time period, in 1980 the average premium was only 277 basis points, whereas in 2018 it averaged 668 basis points. Fig. 5 shows the difference between the authorized return on equity and the riskless rate for each case in the data over the past thirty-eight years. Although the premium is determined against the riskless rate of return (represented here as the yield on a 10-year U.S. Treasury note), we also present for comparison the spreads determined against the yield on the Moody's Seasoned Baa Corporate Bond Index to illustrate that the effect is not an artifact of recent monetary policy on Treasury rates. The trends of the two series are quite similar (and both have statistically-significant positive slopes); accordingly, we shall present only the Treasury rate-determined premiums throughout the remainder of this paper.

Given that a large and growing regulated equity premium exists, our question is whether or not it can be explained within an equilibrium asset-pricing framework such as the CAPM. If β were to have increased during the time period in question, for example, the growth of the regulated equity premium may well be explained by the increasing (relative) riskiness of utility equity. As Section 4 demonstrates, however, in fact it cannot.

[8] We used the 10-year constant maturity U.S. Treasury note yield as a proxy for the riskless rate and the yield on the Moody's Seasoned Baa Corporate Bond Index as a proxy for investment-grade corporate bond rates. Both series were obtained from the Federal Reserve's FRED database (Board of Governors of the Federal Reserve System, n.d.-a; n.d.-b).

4. Potential explanations for the premium

Having demonstrated the existence of a large and growing regulated equity premium, we investigate various potential explanations. As we indicated above, we proceed with our investigation of explanations for the premium via the Capital Asset Pricing Model. The CAPM allows three basic mechanisms of action for a change in the risk premium: (i) the manner in which the underlying assets are financed has changed, (ii) the risk of the underlying assets themselves has changed, and/or (iii) the rate at which the market in general prices risk has changed. We explore each in turn and formally test whether the trend in the data can be explained by the CAPM. Finding that it cannot, we then turn to theoretical explanations outside of the CAPM. The potential alternative explanations in Sections 4.5 through 4.7 all represent viable paths for further research.

4.1. Capital structure effects

As corporate leverage increases, the underlying equity becomes riskier and thus deserving of higher expected returns. In finance, the Hamada equation decomposes the CAPM equity beta (β) into an underlying asset beta (β_A) and the impact of capital structure (Hamada, 1969, 1972). Specifically, the Hamada equation states that $\beta = \beta_A\left[1 + (1-\tau)\frac{D}{E}\right]$, where τ is the tax rate and D and E are the debt and equity in the firm's capital structure, respectively. We use the marginal corporate federal income tax rate for the highest bracket, as provided in Internal Revenue Service (n.d.).

One explanation for a growing risk premium would be steadily increasing leverage among regulated utilities. However, regulators also generally approve of specific capital structures as part of the rate-making process. As a result, our database also contains the authorized capital structures for each utility.[9] In fact, utilities are *less* leveraged today than they were in 1980. The average debt-to-equity ratio in the first five years of the data set (1980–1984) was 1.74; in 2014–2018 it was 1.05. More generally, we can observe the impact of leverage

[9] To be clear, the authorized capital structures evaluated here apply to the regulated utility subsidiaries, and not necessarily to any holding companies to which they belong. The holding companies themselves may utilize more or less leverage, but typically the regulated utility subsidiaries are "ring-fenced" so as to isolate them from holding company-level risks. Similarly, rate-of-return regulation would apply only to the regulated subsidiaries, not to the parent holding company. As a result, the capitalization of the regulated entity (studied here) is often different from the capitalization of the publicly-traded entity that owns it.

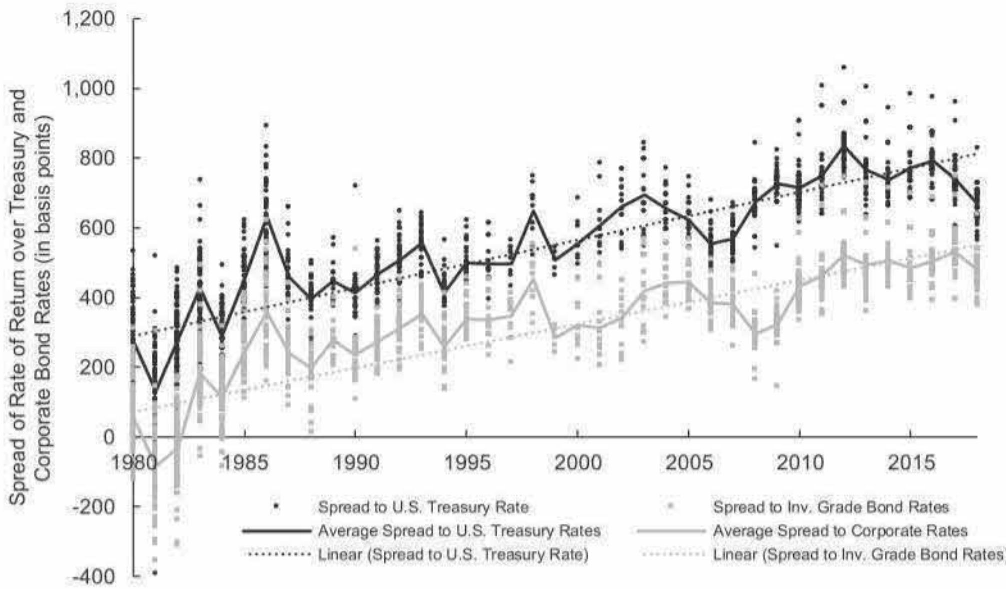

Fig. 5. Authorized return on equity premium, 1980–2018.

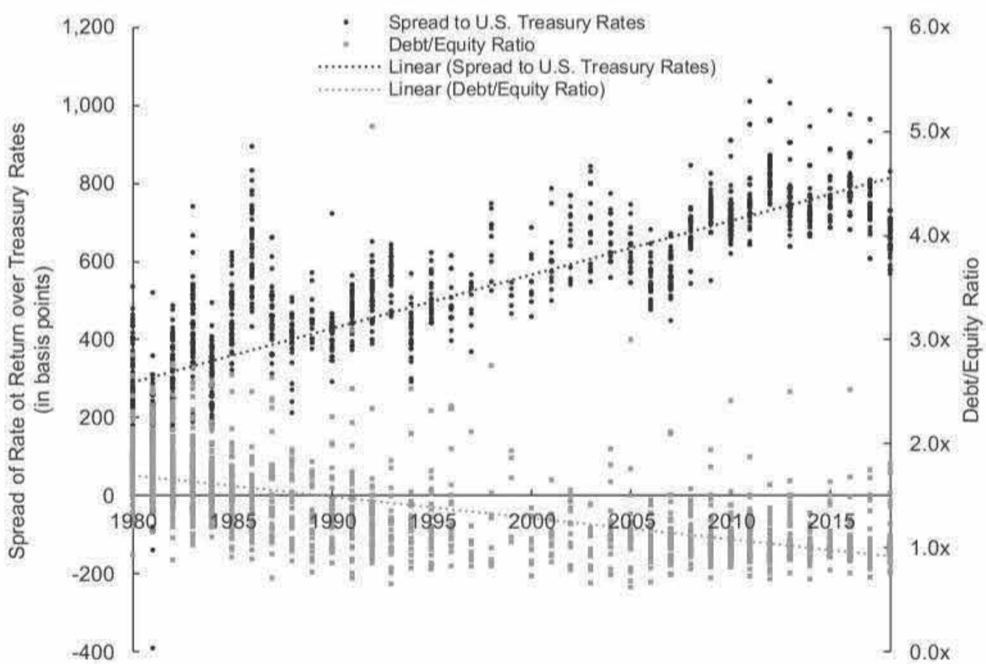

Fig. 6. Authorized return on equity premium vs. utility leverage.

moving in the opposite direction of what one may expect, whether we examine the debt-to-equity ratio exclusively or the Hamada capital structure parameter (i.e., the portion of the Hamada equation multiplied by β_A, or $\left[1 + (1-\tau)\frac{D}{E}\right]$) in its entirety. Figs. 6 and 7 illustrate these results. As a result, it does not appear as if capital structure itself can explain the behavior of the risk premium.

4.2. Asset-specific risk

As noted above, the Hamada equation decomposes returns into compensation for bearing asset-specific risks and for bearing capital structure-specific risks. Even if a firm's capital structure remains unchanged, the riskiness of its underlying assets may change. This risk is represented by the unlevered asset beta, β_A. An increase in the asset beta applicable to such investments would, all else held equal, justify an increase in the risk premium.

To examine such a hypothesis, we used the fifteen members of the Dow Jones Utility Average between 1980 and 2018 as a proxy for "utility asset risk." We estimated five-year equity betas for each firm by regression of their monthly total returns against the total return on the S&P 500 index.[10] The equity betas calculated were then converted to

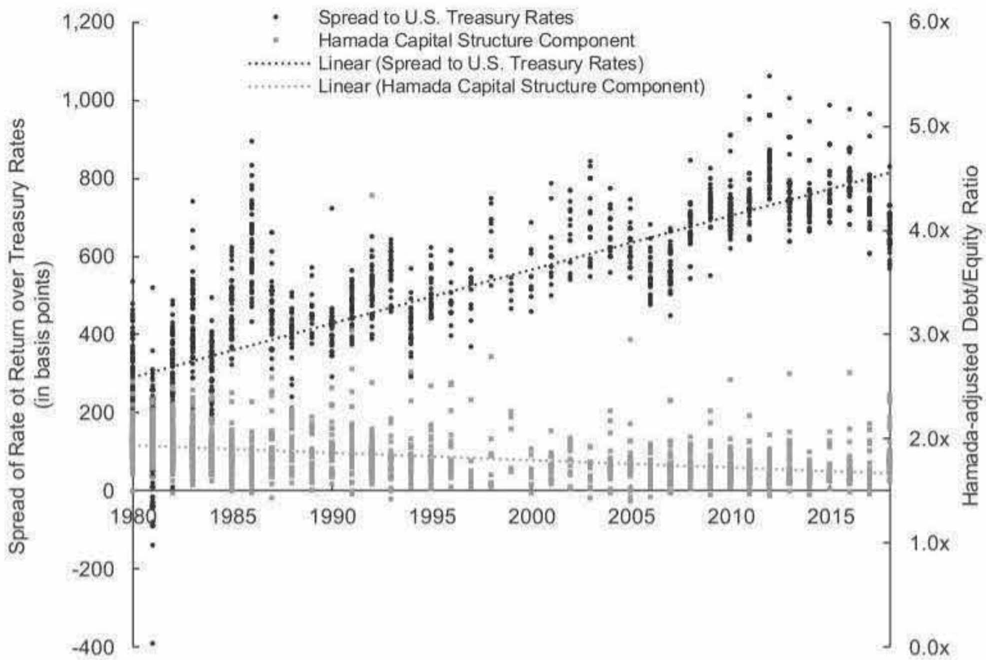

Fig. 7. Authorized return on equity premium vs. the Hamada capital structure parameter.

asset betas using Hamada's equation and corrected for firm cash holdings using firm-specific balance sheet information. We then averaged the fifteen asset betas calculated in each year as our proxy for utility asset risk.[11] The results remain substantively unchanged whether an equal-weighted or a capitalization-weighted average is used.

Although there is, of course, variation in the industry average asset beta across the thirty-eight years, the general trend is down. Fig. 8 presents the risk premium in comparison to the industry average asset beta. As a result, the asset beta is moving in the opposite direction from what one might expect, given a steadily-increasing risk premium, and therefore does not appear to explain the observed behavior of the risk premium.

4.3. The market risk premium

The last CAPM-derived explanation for a changing risk premium relates to the pricing of risk assets in general. If investors require greater compensation for bearing the systematic risk of the market in general, then the risk premium across all assets would increase as well (all else held equal) as a result of the average risk aversion coefficient of investors increasing. The market risk premium reflects this risk-bearing cost in the CAPM.

Although we can observe the *ex post* market risk premium, investors' assessment of the *ex ante* market risk premium is generally based on assuming that historical experience provides a meaningful guide to future experience.[12] It is customary to examine the actual market risk premium over some historical time period and base one's estimate of the *expected* future market risk premium on that historical experience (Sears and Trennepohl, 1993; Villadsen et al., 2017, p. 59). While the size of the historical window is subjective, it is sufficient for our purposes to note that the slope of the market risk premium over time has been negative irrespective of the historical window used.[13] Most sources advocate for using the longest time window available (Villadsen et al., 2017, p. 61); we use a fifty-year historical window for calculation purposes. As Fig. 9 illustrates, that declining trend in the market risk premium appears to be inconsistent with the increasing risk premium exhibited by the rates of return authorized by regulators.

4.4. Testing a theoretical model of the risk premium

Although we have illustrated that each component of the CAPM risk premium appears at odds with the risk premium derived from rates of return authorized by regulators, we now turn to a formal exploration of these relationships. By combining the security market line representation of the CAPM [1] and the Hamada equation, we can define the risk premium, $r_E - r_f$.

$$r_E - r_f = \beta_A \times \left[1 + (1 - \tau)\frac{D}{E}\right] \times MRP \quad (2)$$

In [2], $r_E - r_f$ is the risk premium, or the difference between the authorized rate of return on equity for a given firm in a given rate case and the then-prevailing riskless rate. The asset beta, β_A, is calculated as described in Section 4.2. The middle component is taken from the Hamada equation and reflects the marginal corporate income tax rate (τ) in effect in the year in which the equity return was authorized and the authorized debt-to-equity ratio reflected in the regulators' decision for each case. Lastly, *MRP* is the *ex ante* estimate of the market risk

[10] We determined the composition of the Dow Jones Utility Average index at the end of each year and used a rolling five-year window to perform the regressions. For example, the 1980 regression betas were estimated based on monthly returns from 1975 to 1979, the 1981 regression betas were estimated based on monthly returns from 1976 to 1980, and so on.

[11] The balance sheet and total return data are taken from Standard & Poor's COMPUSTAT database. We calculate $\beta'_A = \beta / \left[1 + (1 - \tau)\frac{D}{E}\right]$ and $\beta_A = \beta'_A / \left[1 - \frac{C}{D+E}\right]$, where C equals the amount of cash and cash equivalents held by each firm and D and E represent, respectively, the debt and equity of each firm. We measure D as the sum of Current Liabilities, Long-Term Debt, and Liabilities–Other in the COMPUSTAT data. Because final firm accounting information was not available for 2018 at the time of writing, we maintained the capital structures calculated using 2017 data.

[12] We do not dwell here on the issue of the "observability" of the market portfolio as it relates to testability of the CAPM. We shall assume that the S&P 500 index is a reasonable proxy for the market portfolio.

[13] The market risk premium data used here are taken from data on the S&P 500 and 10-year U.S. Treasury notes collected from the Federal Reserve (Damodaran, n.d.).

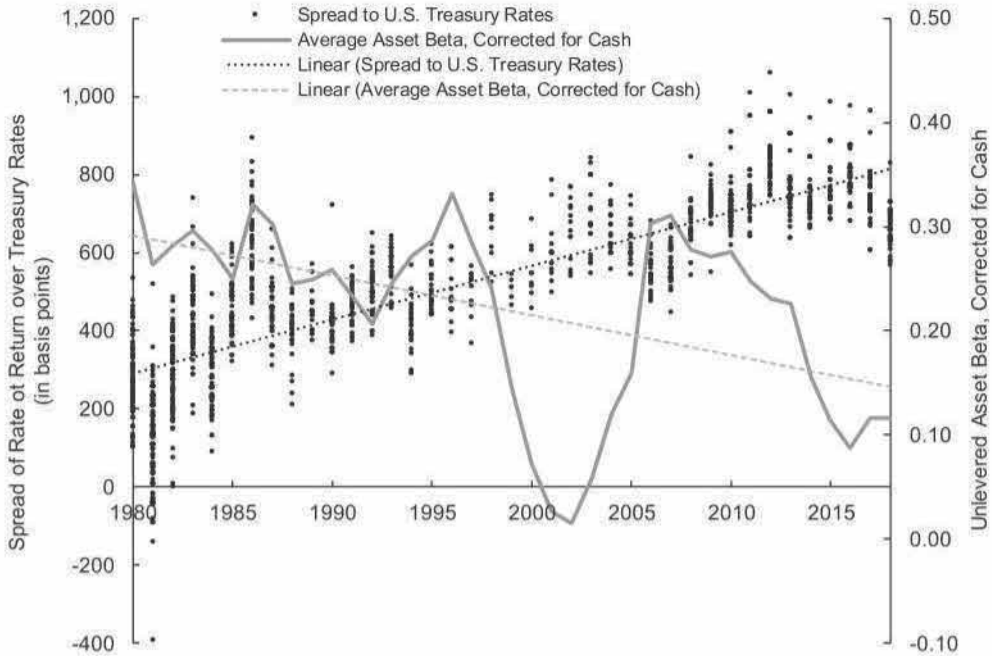

Fig. 8. Authorized return on equity premium vs. industry average asset beta.

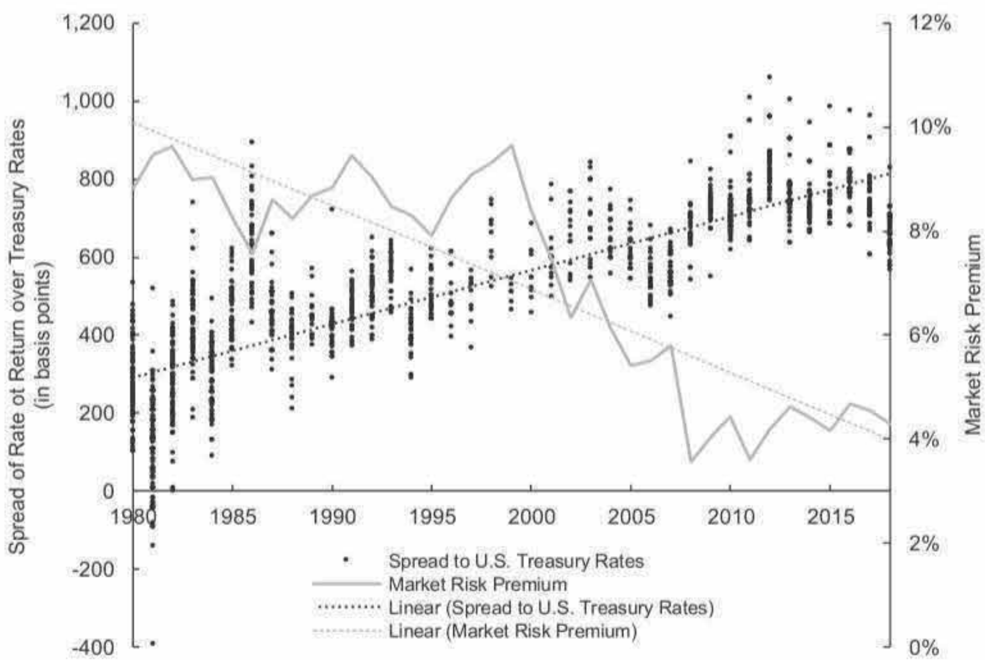

Fig. 9. Authorized rate-of-return premium vs. *ex ante* estimated market risk premium.

premium based on a fifty-year historical window as of the year in which each equity return was authorized.

Let $i = 1, \ldots, N$ index firms and $t = 1, \ldots, T$ index years. Not every firm files a rate case in every year. In addition, firms enter and exit over time due to merger or bankruptcy. Because regulators must have an evidentiary record to support their determinations, we assume that each rate case is evaluated independently in an adversarial hearing across time.

By using a logarithmic transform of [2], we arrive at equation [3].

$$ln(r_{E,it} - r_{f,t}) = \gamma_0 + \gamma_1 ln(\beta_{A,t}) + \gamma_2 ln\left[1 + (1 - \tau_t)\frac{D_{it}}{E_{it}}\right] + \gamma_3 ln(MRP_t) \tag{3}$$

In a traditional ordinary least squares (OLS) regression setting, the CAPM would hypothesize that γ_0 should be zero (or not significant) and γ_1, γ_2, and γ_3 should be positive and significant. What we find, however, is exactly the opposite of that (Table 3). The coefficients are negative and strongly significant. Further, a comparison of the observed risk premium to the risk premium estimated by our regression model reveals a good fit (Fig. 10). The negative coefficients are problematic for the CAPM, but also suggest rather counterintuitive effects at an applied

Table 3
Regression results for CAPM-based risk premium model. Coefficients for both the OLS regression model and a model controlling for utility-level fixed effects are shown.

	OLS	Controlling for utility-level fixed effects
	$ln(r_E - r_f)$	$ln(r_E - r_f)$
γ_0, Constant	3.641****	
	(0.130)	
γ_1, Asset beta, $ln(\beta_A)$	−0.158****	−0.156****
	(0.022)	(0.023)
γ_2, Capital structure, $ln\left[1 + (1 - \tau)\frac{D}{E}\right]$	−0.492****	−0.967****
	(0.103)	(0.142)
γ_3, Market risk premium, $ln(MRP)$	−0.947****	−0.898****
	(0.035)	(0.039)
R-squared	46.4%	46.6%
Adjusted R-squared	46.3%	41.2%
F statistic	458.8****	420.9****
No. of observations	1596	1596

Standard errors are reported in parentheses.
*, **, ***, and **** indicate significance at the 90%, 95%, 99%, and 99.9% levels, respectively.

level. Regulators use CAPM prescriptively in rate cases; they are determining what utilities *should* earn. A negative capital structure coefficient suggests, for example, that investors in firms with high leverage *should* be compensated with *lower* returns. Similarly, negative coefficients imply that investors in firms with riskier assets (higher asset betas) and during periods of higher risk aversion (higher market risk premiums) should also be compensated with *lower* returns. These results would be difficult for regulators to justify on normative grounds.

It may be the case, however, that common cross-sectional variation is biasing the results for this data by creating endogeneity issues for the OLS-estimated coefficients. For example, the repeated presence of the same utilities over time could introduce entity-level fixed effects into the analysis. Accordingly, we performed an F-test to evaluate the presence of individual-level effects in the data (Judge et al., 1985: p. 521). The test strongly supports the presence of individual (utility-level) effects ($F_{143,1449} = 1.5$, $p < 0.001$). In addition, the Hausman test (Hausman, 1978; Hausman and Taylor, 1981) supports the fixed-effect specification in lieu of random effects ($\chi^2(3) = 24.0$, $p < 0.001$). As a result, Table 3 also provides the regression coefficients controlling for utility-level fixed effects. These coefficients, while numerically different than the OLS results, are nevertheless still negative and strongly significant, in conflict with both financial theory and regulator intent.

Fig. 10 also reveals a distinct shift in the predicted trend of the risk premium beginning in 1999. This is notable because for many parts of the U.S., 1999 represented the year that implementation of electric market reform and restructuring began, with wholesale markets such as ISO-New England opening and several divestiture transactions of formerly-regulated generating assets occurring, establishing market valuations for formerly regulated assets (Borenstein and Bushnell, 2015). In addition, FERC issued its landmark Order 2000 encouraging the creation of Regional Transmission Organizations. To examine this point in time, we divided the data into two sets, 1980–1998 and 1999–2018, and estimated separate regression models for each subset using both OLS and controlling for utility-level fixed effects (Table 4). As before, the F (pre-1999 $F_{129,805} = 1.6$, $p < 0.001$; post-1998 $F_{129,525} = 3.2$, $p < 0.001$) and Hausman (pre-1999 $\chi^2(3) = 15.5$, $p < 0.01$; post-1998 $\chi^2(3) = 23.8$, $p < 0.001$) tests both strongly support the model controlling for utility-level fixed effects over OLS.

Although the results in both cases are consistent with our earlier finding that the standard finance model appears at odds with the empirical data, the two regression models are noticeably different from one another and appear to better represent the data (Fig. 11). We performed the Chow (1960) test and confirmed the presence of a structural break in the data in 1999 ($F_{4,1588} = 91.6$, $p < 0.001$).[14] We find this result suggestive that deregulatory activity may have an influence even on still-regulated utilities—a point to which we shall return in Section 5.2.

4.5. Potential finance explanations other than the CAPM

In Mehra and Prescott's (2003) review of the equity premium puzzle literature, the authors acknowledge that uncertainty about changes in the prevailing tax and regulatory regimes may explain the premium. Such forces may also be at work with regard to regulated rates of return. To the extent that investors require higher current rates of return because they are concerned about future shocks to the tax or regulatory structure of investments in regulated electric utilities (e.g., EPA's promulgation of the Clean Power Plan, the U.S. Supreme Court's stay of the Clean Power Plan, expiration of tax credits), such concern may be manifest in a higher degree of risk aversion that is unique to investors in the electric utility sector, and therefore a higher "market" risk premium on the assumption that capital markets are segmented for electric utilities.

A separate line of inquiry concerns a criticism of the Hamada equation in the presence of risky debt (Hamada (1972) excluded default from consideration). Conine (1980) extended the Hamada equation to accommodate risky debt by applying a debt beta. Subsequently, Cohen (2008) sought to extend the Hamada equation by adjusting the debt-to-equity parameter to incorporate risky debt in the calculation of the equity beta [4].

$$\beta = \beta_A\left[1 + (1 - \tau)\frac{r_D}{r_f}\frac{D}{E}\right] \tag{4}$$

We view neither of these proposed solutions as entirely satisfying, and note that they tend to be material only for high leverage, which is not common to regulated utilities. Nevertheless, we acknowledge that adjustments to the capital structure may influence the risk premium. However, applying the Cohen (2008) modification and using the Moody's Seasoned Baa Corporate Bond Yield as a proxy for the cost of risky debt (r_D), we note that our regression results are substantively unchanged. As Table 5 illustrates, use of the Cohen betas still results in highly significant, but negative coefficients, which is contrary to theory. These results are maintained when controlling for utility-level fixed effects, and the F (Hamada $F_{143,1449} = 1.5$, $p < 0.001$; Cohen $F_{143,1449} = 1.3$, $p < 0.01$) and Hausman (Hamada $\chi^2(3) = 24.0$, $p < 0.001$; Cohen $\chi^2(3) = 6.3$, $p < 0.1$) tests are significant in support of the fixed effects model.

In lieu of modifying the CAPM parameters, some researchers have suggested that Ross's (1976) Arbitrage Pricing Theory (APT) is preferable to the CAPM because the CAPM produces a "shortfall" in estimated returns (Roll and Ross, 1983) and "underestimates" actual returns in utility settings (Pettway and Jordan, 1987). While the works of these authors are suggestively similar to the analysis contained in this paper, we note that those authors were examining the *actual* returns on utility common stocks, rather than the rates of return *authorized* by regulators for assets held in utility rate bases. The distinction is important. In the case of the former, it is a question of asset pricing models and efficient capital markets. In the case of the latter, it is an issue of regulator judgment. We note specifically that regulators are making decisions that set these rates, and in many cases are doing so explicitly stating that they are relying in whole or in part on the CAPM. Our question concerns not just whether the CAPM is a better asset pricing model (than the APT, for example), but whether regulators' own judgment can

[14] Additional testing using the Andrews (1993) approach supports the presence of structural breaks during the transitional regulatory period identified by Borenstein and Bushnell (2015), confirming the appropriateness of our selection of 1999 as a year with strong historical motivation for a structural break.

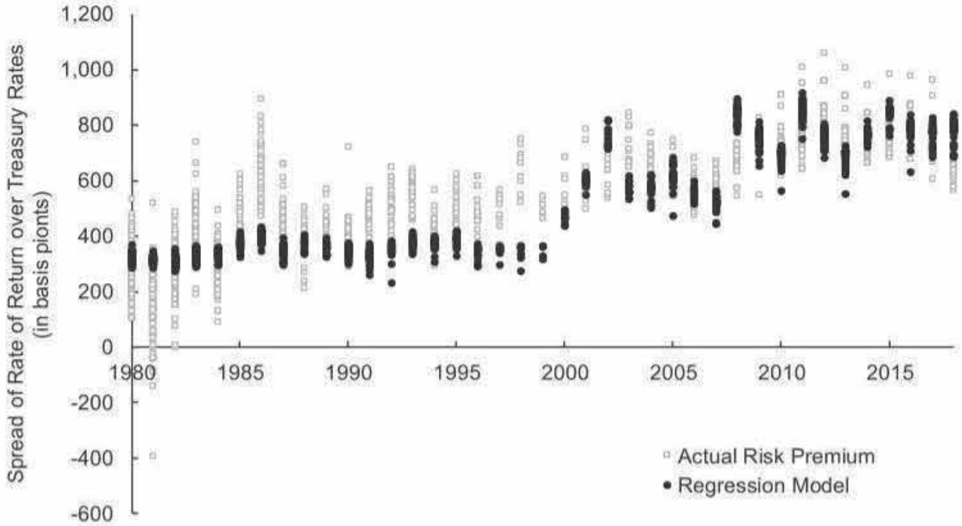

Fig. 10. Actual vs. OLS regression-model risk premium.

Table 4
Regression results for a two-period CAPM-based risk premium model. For purposes of the Chow test, the combined sum of squared residuals was 272.5. Coefficients for both the OLS regression model and a model controlling for utility-level fixed effects are shown.

	OLS		Controlling for utility-level fixed effects	
	1980–1998	1999–2018	1980–1998	1999–2018
	$ln(r_E - r_f)$	$ln(r_E - r_f)$	$ln(r_E - r_f)$	$ln(r_E - r_f)$
γ_0, Constant	−6.259****	5.159****		
	(0.718)	(0.093)		
γ_1, Asset beta, $ln(\beta_A)$	−0.940****	−0.071****	−0.972****	−0.065****
	(0.131)	(0.008)	(0.135)	(0.008)
γ_2, Capital structure, $ln\left[1 + (1 - \tau)\frac{D}{E}\right]$	−0.140	−0.325****	−0.865****	−0.636****
	(0.150)	(0.049)	(0.224)	(0.075)
γ_3, Market risk premium, $ln(MRP)$	−4.529****	−0.471****	−4.326****	−0.432****
	(0.261)	(0.026)	(0.267)	(0.025)
R-squared	26.7%	36.9%	30.2%	44.9%
Adjusted R-squared	26.4%	36.6%	18.8%	31.0%
F statistic	113.3****	127.3****	116.0****	142.5****
Sum of squared residuals	214.4	8.4	170.8	4.7
No. of observations	938	658	938	658

Standard errors are reported in parentheses.
*, **, ***, and **** indicate significance at the 90%, 95%, 99%, and 99.9% levels, respectively.

be explained by the model on which they claim to rely.

Lastly, to address a related point, we also examined the actual earned rates of return on equity for the 15 utilities in the Dow Jones Utility Average over our historical window. We used each firm's actual return on equity, calculated annually as Net Income divided by Total Equity, as reported in the COMPUSTAT database. This measure of firm profitability examines how successful the firms were at converting their *authorized* returns into *earned* returns. In general, the earned returns closely tracked the authorized returns, suggesting that the decisions of regulators are significantly influencing the actual earnings of regulated utilities. Fig. 12 compares the spread of *authorized* rates of return over riskless rates to the spread of *earned* rates of return over riskless rates and to the median net income of utilities in constant 2018 dollars.[15] The steadily increasing risk premium we have identified is present in both series. The series are correlated at 0.77 (authorized vs. earned), 0.59 (authorized vs. median net income), and 0.75 (earned vs. median net income), all of which are significantly greater than zero ($p < 0.001$). Further, the "capture rate" (the percentage of authorized rates actually earned by the utilities) averaged 96% over the entire time period. As a result, we conclude that the trend of increasing risk premiums is not an abstract anomaly occurring in a regulatory vacuum, but rather a direct contributor to the earnings of regulated utilities.

However, these measures of firm performance must be interpreted with caution. The authorized rates of return apply to jurisdictional utilities, while the earned rates of return are calculated based on holding company performance, which in many cases are not strictly equivalent. Further, increasing net income may be due to industry consolidation producing larger firms (with income increasing only proportionally to size), rather than an increase in profitability itself. In fact, the average income-to-sales ratio of the Dow Jones Utility Average members remained remarkably stable across the period of our study,

[15] We used the median earned rate of return over the 15 Dow Jones utilities. The results are substantively equivalent if the average earned rate of return is used but are more volatile due to the impact on earnings of the California energy crisis of 2000–2001 and the collapse of Enron in 2001.

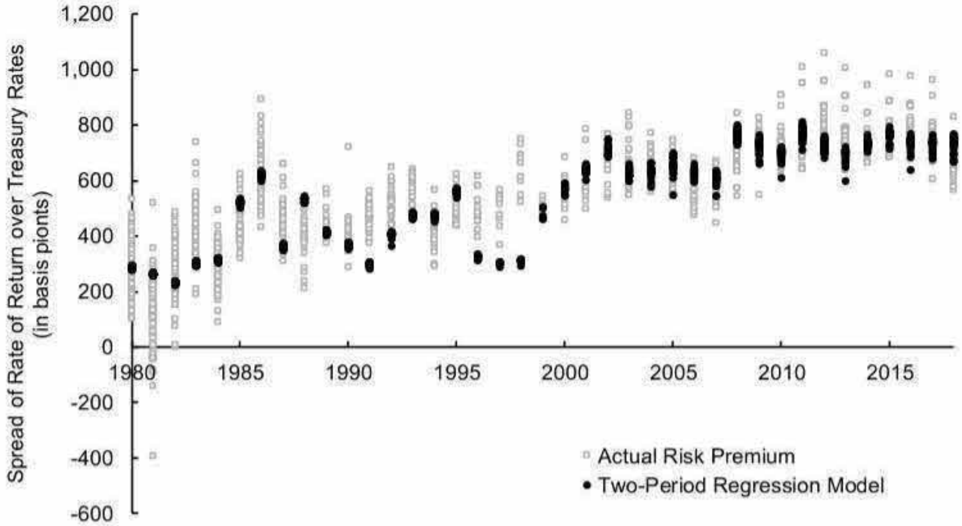

Fig. 11. Actual vs. two-period OLS model-predicted risk premium.

Table 5
Regression results for the standard Hamada capital structure model and Cohen (2008) capital structure model that incorporates risky debt. Coefficients for both the OLS regression model and a model controlling for utility-level fixed effects are shown.

	OLS		Controlling for utility-level fixed effects	
	Hamada $ln(r_E - r_f)$	Cohen $ln(r_E - r_f)$	Hamada $ln(r_E - r_f)$	Cohen $ln(r_E - r_f)$
γ_0, Constant	3.641**** (0.130)	3.191**** (0.085)		
γ_1, Asset beta, $ln(\beta_A)$	−0.158**** (0.022)	−0.169**** (0.022)	−0.156**** (0.023)	−0.175**** (0.023)
γ_2, Capital structure, $ln\left[1+(1-\tau)\frac{D}{E}\right]$	−0.492**** (0.103)		−0.967**** (0.142)	
γ_2', Capital structure, $ln\left[1+(1-\tau)\frac{r_D}{r_f}\frac{D}{E}\right]$		−0.156* (0.081)		−0.275*** (0.040)
γ_3, Market risk premium, $ln(MRP)$	−0.947**** (0.035)	−1.046**** (0.036)	−0.898**** (0.039)	−1.087**** (0.040)
R-squared	46.4%	45.7%	46.6%	45.1%
Adjusted R-squared	46.3%	45.6%	41.2%	39.6%
F statistic	458.8****	447.1****	420.9****	396.9****
No. of observations	1596	1596	1596	1596

Standard errors are reported in parentheses.
*, **, ***, and **** indicate significance at the 90%, 95%, 99%, and 99.9% levels, respectively.

and actually slightly declined, suggesting that gains in net income came from growing revenue, rather than increasing margins (although revenue growth may itself be a function of rising authorized rates of return). Nevertheless, the results are suggestive.

We have not repeated the analysis of Roll and Ross (1983) and Pettway and Jordan (1987) and examined the relationship between firm performance and stock performance. Their findings, however, suggest that regulated utilities have realized *higher* stock returns than can be explained by the CAPM—a finding congruent with our work and suggestive of other factors being priced by the market. This does not entirely explain the judgment issue, however: why regulators appearing to use a CAPM approach provide utilities with returns that also appear to be excessive.

4.6. Potential public choice explanations

Another category of potential explanations emerges from the public choice literature on the role of institutional factors. Regulators may be deliberately or inadvertently providing a "windfall" of sorts to electric utilities. Stigler (1971), among others in the literature on regulatory capture, noted that firms may seek out regulation as a means of protection and self-benefit. This is particularly true when the circumstances are present for a collective action problem (Olson, 1965) of concentrated benefits (excess profits to utilities may be significant) and diffuse costs (the impact of those excess profits on each individual ratepayer may be small). Close relationships between regulators and the industries that they regulate have been observed repeatedly, and one possible explanation for the size and growth of the risk premium is the electric utility industry's increasing "capture" of regulatory power.

We are somewhat skeptical of this explanation, however, both because of the degree of intervention in most utility rate cases by non-utility parties, and because the data do not suggest that regulators have become progressively laxer over time. Fig. 13 compares the rates of return on equity *requested* by utilities in our data set against the rates of return ultimately authorized. As the trend line illustrates, this ratio has remained remarkably stable (within a few percent) over the thirty-eight

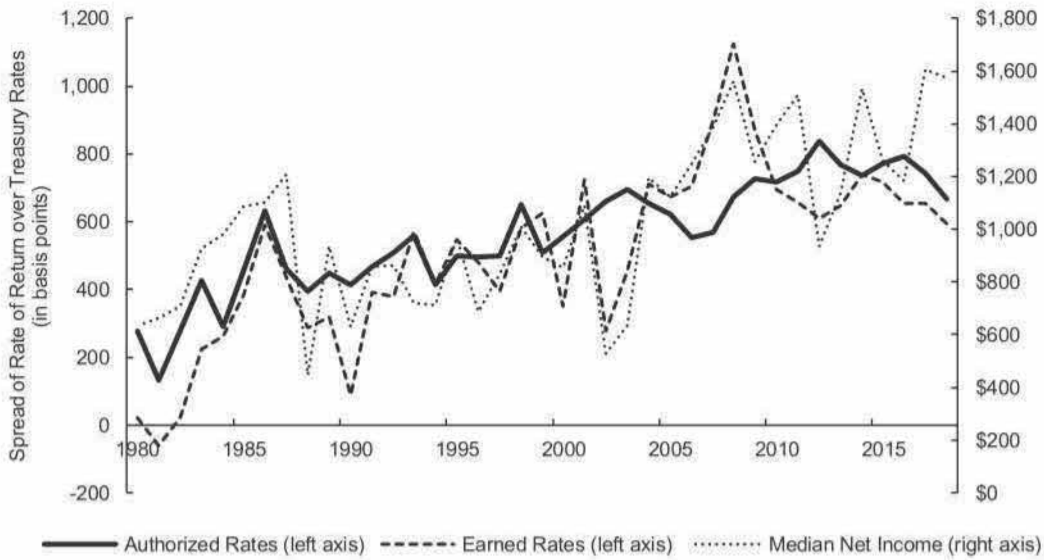

Fig. 12. Comparability of spreads measured with authorized and earned rates of return and utility net income.

years of data, even as the risk premium itself has steadily increased. As a result, the data do not suggest in general an obvious, growing permissiveness on the part of regulators. However, the last nine years are *suggestive* of an increasing level of accommodation among regulators. We propose a possible explanation for this particular pattern in Section 4.7.

To examine the public choice issues further, we investigated whether the risk premiums were related to the selection method of public utility commissioners and whether or not the rate cases in question were settled or fully litigated. The traditional hypothesis has been that elected (instead of appointed) commissioners were less susceptible to capture, more "responsive" to the public, and therefore more pro-consumer. Further, that cases that were settled were more likely to be accommodating to utilities (as money was "left on the table") and therefore would result in higher rates.

A sizable body of literature, however, has largely rejected the selection method hypothesis. Hagerman and Ratchford (1978) and Primeaux and Mann (1986) concluded that the selection method had no impact on returns or electricity prices respectively. Others have agreed that the selection method alone doesn't matter; it is how closely the regulators selected are monitored that matters (Boyes and McDowell, 1989). In addition, whatever evidence of an effect that may exist is likely due to selection method being a proxy for states with different intrinsic structural conditions (Harris and Navarro, 1983). Lastly, while states with elected utility commissioners (Kwoka, 2002) or commissioners whose appointment by the executive requires approval by the legislature (Boyes and McDowell, 1989) tend to have lower electricity prices, those low prices may create the perception of an "unfavorable" investment climate and may therefore lead to a higher cost of capital (Navarro, 1982). Alternatively, if lower prices are observed, it then remains unclear who actually pays (utility shareholders in foregone profits or consumers in higher costs of capital) for the lower observed prices (Besley and Coate, 2003).

To examine the impact of commission selection method and means of case resolution on risk premium, we categorized each state as having an elected or appointed utility commission based on data in Costello (1984), Besley and Coate (2003), and Advanced Energy Economy (2018). In addition, each rate case was reported as being either fully litigated or settled. The literature has hypothesized (but largely not found) that elected commissions are more "responsive" and therefore more pro-consumer. As a result, the expectation would be that the risk premiums implicit in authorized rates were higher for appointed commissions. Similarly, for means of case resolution, risk premiums would be higher for settled, rather than fully litigated rate cases.

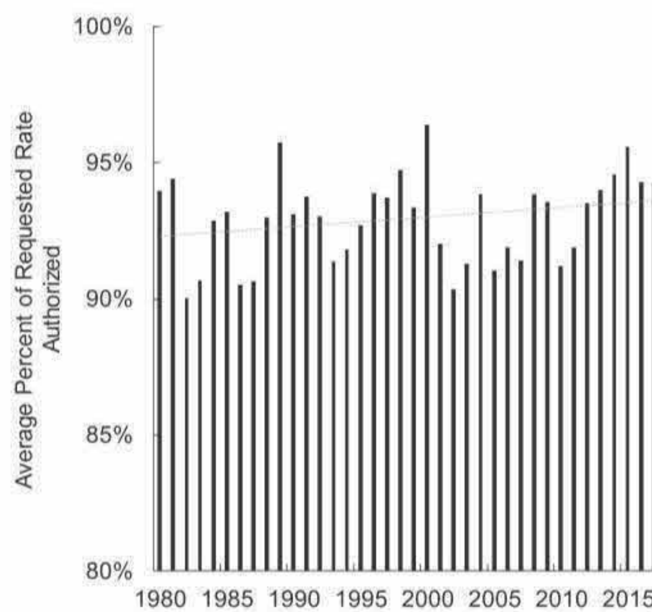

Fig. 13. Rate of return authorized as a percent of rate of return requested.

Table 6
Average risk premium in basis points by commission selection method and means of case resolution. The number of cases in each group is provided in parentheses.

	Appointed Commissions	Elected Commissions	Subtotals
Settled Cases	612 (367)	697 (89)	629 (456)
Fully Litigated Cases	460 (1008)	488 (181)	464 (1189)
Subtotals	500 (1375)	557 (270)	510 (1645)

Like other authors, we found no significant effect *overall* for selection method, but a very significant effect for whether cases were settled or fully litigated. In addition, there appears to be a significant *interaction* between selection method and means of case resolution, suggesting that the lack of evidence of an effect in the literature may be related to its interaction with the means of case resolution, which has not been examined in this depth before. Table 6 illustrates the average risk

Table 7
Regression results for the standard CAPM model and the CAPM model plus two public choice variables (commission selection method and means of case resolution). Coefficients for both the OLS regression model and a model controlling for utility-level fixed effects are shown.

	OLS		Controlling for utility-level fixed effects	
	CAPM $ln(r_E - r_f)$	CAPM + Public Choice $ln(r_E - r_f)$	CAPM $ln(r_E - r_f)$	CAPM + Public Choice $ln(r_E - r_f)$
γ_0, Constant	3.641****	3.519****		
	(0.130)	(0.137)		
γ_1, Asset beta, $ln(\beta_A)$	−0.158****	−0.159****	−0.156****	−0.154****
	(0.022)	(0.022)	(0.023)	(0.023)
γ_2, Capital structure, $ln\left[1+(1-\tau)\frac{D}{E}\right]$	−0.492****	−0.463****	−0.967****	−0.917****
	(0.103)	(0.102)	(0.142)	(0.141)
γ_3, Market risk premium, $ln(MRP)$	−0.947****	−0.927****	−0.898****	−0.858****
	(0.035)	(0.036)	(0.039)	(0.041)
γ_4, Settle = 1		0.223***		0.249****
		(0.057)		(0.060)
γ_5, Appointed = 1		0.159****		0.132**
		(0.034)		(0.058)
γ_6, Settle = 1 × Appointed = 1		−0.182***		−0.197***
		(-0.061)		(-0.065)
R-squared	46.4%	47.4%	46.6%	47.3%
Adjusted R-squared	46.3%	47.2%	41.2%	41.9%
F statistic	458.8****	238.5****	420.9****	216.5****
AIC	−2809	−2810		
No. of observations	1596	1596	1596	1596

Standard errors are reported in parentheses.
*, **, ***, and **** indicate significance at the 90%, 95%, 99%, and 99.9% levels, respectively.

premium observed in each group. The average risk premium for settled cases is significantly higher than for fully litigated cases ($p < 0.001$). Further, while the average risk premium for settled cases and appointed commissions is significantly greater than for fully litigated cases and elected commissions ($p < 0.001$), there is an interaction effect suggesting that the impact of selection method on risk premium depends on the means of case resolution ($p < 0.05$).

Notwithstanding these differences, the incremental explanatory value of these public choice variables is minimal (but significant). Table 7 compares the standard CAPM model with an OLS model that incorporates selection method and means of case resolution. The Akaike Information Criterion (AIC) indicates that incorporation of the public choice variables has only slight incremental value. We estimate that the marginal impact is only approximately 8 basis points—much less than the observed increase over time.[16] As before, the F (CAPM $F_{143,1449} = 1.5$, $p < 0.001$; CAPM + Public Choice $F_{143,1446} = 1.4$, $p < 0.001$) and Hausman (CAPM $\chi^2(3) = 24.0$, $p < 0.001$; CAPM + Public Choice $\chi^2(6) = 24.1$, $p < 0.001$) tests strongly support controlling for utility-level fixed effects in the model. Table 7 also includes coefficients incorporating such controls.

4.7. Potential behavioral economics explanations

To this point, we have examined a number of factors related to economic and institutional influences. At the outset, however, we noted the potential for rate determination to be influenced by regulator judgment. In many cases there is evidence that regulators are not behaving in accordance with the method they in fact purport to be using (i.e., CAPM). As we cannot escape the fact that ultimately the authorized return on equity is a product of regulator decision-making, we now consider possible explanations for the risk premium based on insights from behavioral economics.

First, we note that regulator attachment to rate decisions from the recent past may be coloring their forward-looking decisions. Earlier we referenced a report from Pennsylvania regulators about their stated reliance on (*inter alia*) "recent [returns on equity] adjudicated by the Commission" (Pennsylvania Public Utility Commission, 2016, p. 17). The legal weight attached to precedent may give rise here to a recency bias, where regulators anchor on recent rate decisions and insufficiently adjust them for new information. While stability in regulatory decision-making is seen as useful in assuring investors, to the extent that it results in a slowing of regulatory response when market conditions change, regulators should be encouraged to weigh the benefits of stability against the costs of distortionary responses to authorized returns that lag market conditions.

Our second insight from behavioral economics involves a curious observation in the empirical data: the average rate of return on regulated equity appears to have "converged" to 10% over time. Although the underlying riskless rate has continued to drop, authorized equity returns have generally remained fixed in the neighborhood of 10%, only dropping below (on average) over the last few years. Anecdotally, we have observed a reluctance among potential electric power investors to accept equity returns on power investments of less than 10%—even though those same investors readily acknowledge that *debt* costs have fallen. To that extent, then, a behavioral bias may be at work.

The finance literature has noted a similar effect related to crossing index threshold points (e.g., every thousand points for the Dow Jones Industrial Average). These focal points, which have no normative import, appear to influence investor behavior. Trading is reduced near major crossings (Donaldson and Kim, 1993; Koedijk and Stork, 1994; Aragon and Dieckmann, 2011), with some asserting that the behavior of investors in clienteles may produce this behavior (Balduzzi et al., 1997). We propose a related theory.

In economics, "money illusion" refers to the misperception of nominal price changes as real price changes (Fisher, 1928). Shafir et al. (1997) proposed that this type of choice anomaly arises from framing effects, in that individuals give improper influence to the nominal representation of a choice due to the convenience and salience of the nominal representation. The experimental results have been upheld in several subsequent studies in the behavioral economics literature (Fehr and Tyran, 2001; Svedsäter et al., 2007).

The effect here may be similar: investors and regulators may conflate "nominal" rates of return (the authorized rates) with the risk

[16] For example, the marginal impact of a settled vs. fully-litigated case would be $exp(3.513 + 0.223) - exp(3.513) = 8.4$ using the OLS coefficients.

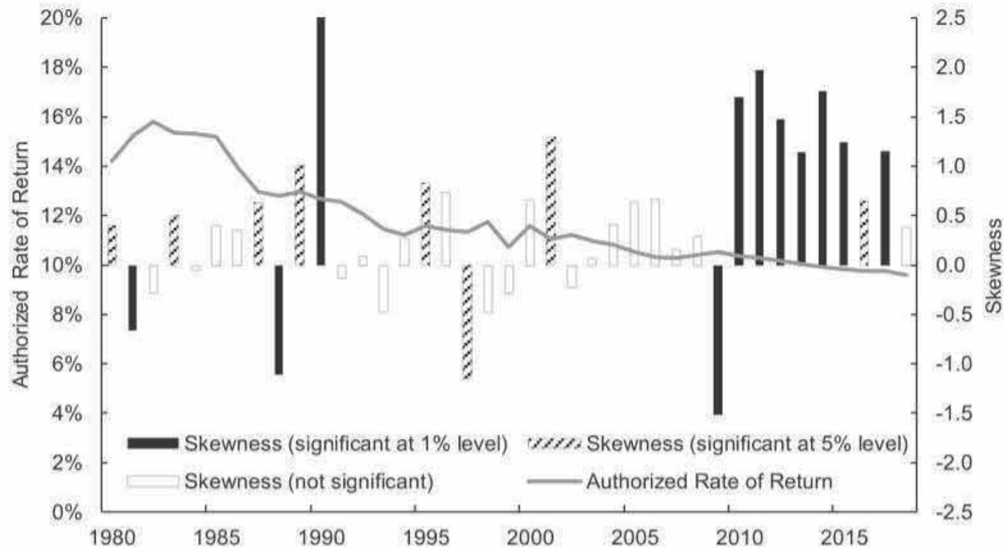

Fig. 14. Authorized rates of return on equity and skewness.

premium underlying the authorized rate. The apparent "stickiness" of rates of return on equity around 10% is similar to the "price stickiness" common in the money illusion (and, indeed, the rate of return is the price of capital). If there was in fact a tendency (intentional or otherwise) to respect a 10% "floor," one might expect that the distribution of authorized returns within each year may "bunch up" in the left tail at 10%, where absent such a floor one may expect them to be distributed symmetrically around a mean. As Fig. 14 illustrates, we see precisely such behavior. As average authorized returns decline to 10% (between 2010 and 2015), the skewness of the within-year distributions of returns becomes persistently and statistically significantly positive, suggesting a longer right-hand tail to the distributions, consistent with a lack of symmetry below the 10% threshold.[17] We note also that this period of statistically significant positive skewness coincides precisely with what appeared to be a period of increased regulator accommodation in Fig. 13. Further, once the threshold is definitively crossed, skewness appears to moderate and the distribution of returns appears to revert toward symmetry.

A related finding has been reported by Fernandez and colleagues (Fernandez et al., 2015, 2017, 2018), where respondents to a large survey of finance and economics professors, analysts, and corporate managers tended, on average, to overestimate the riskless rate of return. In addition, their estimates exhibited substantial positive skew, in that overestimates of the riskless rate far exceed underestimates.[18] The authors found similar results not just in the U.S., but also in Germany, Spain, and the U.K. In the U.S., the average response during the high skewness period exceeded the contemporaneous 10-year U.S. Treasury rate by 20–40 basis points, before declining as skewness moderated in 2018. It may be that overestimating the riskless rate is simply one way for participants in regulatory proceedings to "rationalize" maintaining the authorized return in excess of 10%. Alternatively, it may be an additional bias in the determination of authorized rates of return.

If such biases exist, there are clear implications for the regulatory function itself. For example, this apparent 10% "floor" was even recognized recently in a U.S. Federal Energy Regulatory Commission proceeding (Initial Decision, Martha Coakley, et al. v. Bangor Hydro-Electric Co., et al., 2013, 144 FERC 63,012 at 576): "if [return on equity] is set substantially below 10% for long periods [...], it could negatively impact future investment in the (New England Transmission Owners)." Our findings here draw us back to Joskow's (1972) characterization of regulator decision-making as a sort of meta-analysis. That is, commissioners do not merely directly evaluate the CAPM equations. Rather, they look at the nature of the evidence *as presented to them*. Accordingly, their judgments are based not just on capital market conditions in a vacuum, but on the format, detail, and context of the information contained within the evidentiary record of a rate case. As a result, regulators are susceptible to biases in judgment, and calibration of regulatory decision-making during the rate-setting process should be a required step.

5. Conclusions and policy implications

In this paper, we have examined a database of electric utility rates of return authorized by U.S. state regulatory agencies over a thirty-eight-year period. These rates have demonstrated a growing spread over the riskless rate of return across the time horizon studied. The size and growth of this spread—the risk premium—does not appear to be consistent with classical finance theory, as expressed by the CAPM. In fact, regression analysis of the data suggests the *opposite* of what would be predicted if the CAPM holds. This is particularly perplexing given that regulators often *claim* to be using the CAPM. In addition to the traditional finance factors, our work examined the influence of institutional, structural, and behavioral factors on the determination of authorized rates of return. We find support for many of these factors, although most cannot be justified on traditional normative grounds.

The pattern of large and growing risk premiums illustrated in this paper has significant implications for both utility and infrastructure investment and regulation and market design in environments where both regulated and restructured firms compete for capital. In particular, if rate case activity increases over the next several years as rate moratoria expire, the implications for retail rate escalation and capital investment may be significant. We discuss each in turn before offering some thoughts on possible mitigating factors.

[17] Formally, we test the hypothesis that the observed skewness is equal to zero (a symmetric, normal distribution). The test statistic is equal to the skewness divided by its standard error $\sqrt{6n(n-1)/(n-2)(n+1)(n+3)}$, where n is the sample size. The test statistic has an approximately normal distribution (Cramer and Howitt, 2004).

[18] At the time of the 2015 survey, for example, the 10-year U.S. Treasury rate was 2.0%. The average riskless rate reported by the 1983 U.S. survey respondents was 2.4% (median 2.3%), but responses ranged from 0.0% to 8.0%.

Fig. 15. Peak wholesale (2007–2018) vs. retail (2007–2017) power prices. Wholesale prices represent the average annual peak electricity price in MISO-IN, ISO-NE Mass Hub, Mid-C, Palo Verde, PJM-West, SP-15, and ERCOT-North. Retail prices collected from U.S. Energy Information Administration (https://www.eia.gov/electricity/data/state/avgprice_annual.xlsx). The retail price is the average for the entire country (using only the 7 states with wholesale markets included does not change the result).

5.1. *Wholesale and retail electricity price divergence*

A growing divergence has emerged over the last decade. Although fuel costs and wholesale power prices have declined since 2007, the *retail* price of power has increased over the same period (see Fig. 15). One explanation for this divergence in wholesale and retail rates may be the presence of a growing premium attached to regulated equity returns and therefore embedded into rates. To be sure, other forces may also be at work (for example, recovery of transmission and distribution system investments is consuming a greater portion of retail bills—a circumstance potentially exacerbated by excessive risk premiums). Further, even if the growing divergence between wholesale and retail rates is related to a growing risk premium, it does not necessarily follow that such growth is inappropriate or inconsistent with economic theory. Nevertheless, the potential for embedding of such quasi-fixed costs into the cost structure of electricity production may be significant for end users, as efficiency gains on the wholesale side are more than offset by excess costs of equity capital on the retail side.

5.2. *Regulation itself as a source of risk*

Public policy, or regulation itself, may be a causal factor in the observed behavior of the risk premium. The U.S. Supreme Court acknowledged, in *Duquesne Light Company* et al. *v. David M. Barasch* et al. (488 U.S. 299 (1989), p. 315) that "the risks a utility faces are in large part defined by the rate methodology, because utilities are virtually always public monopolies dealing in an essential service, and so relatively immune to the usual market risks." The recognition that the very act of regulating utilities subjects them to a unique class of risks may influence their cost of capital determination. And yet, if the *purpose* (or at least *a* purpose) of regulating electric utilities is to prevent these quasi-monopolists from charging excessive prices, but the *practice* of regulating them results in a higher cost of equity capital than might otherwise apply, it calls into question the role of such regulation in the first place.

Similarly, we may also question whether the hybrid regulated and non-regulated nature of the electric power sector in the U.S. plays a role as well. Has deregulation caused risk to "leak" into the regulated world because both regulated and non-regulated firms must compete for the same pool of capital? Has the presence of non-regulated market participants raised the marginal price of capital to all firms? In Section 4.4 we illustrated a shift in the trend of risk premium growth in 1999, as several U.S. markets were switching to deregulation, but further study of this question is needed.

The trajectory of public policy during the entire time period studied has been toward deregulation (beginning before 1980 with Public Utility Regulatory Policy Act, through the Natural Gas Policy Act in the 1980s, and electric industry deregulation in the 1990s) and "today's investments face market, political and regulatory risks, many of which have no historical antecedent that might serve as a starting point for modeling risk." (PJM Interconnection, 2016) The general unobservability of the *ex ante* expected returns on deregulated assets complicates determining if the progressive deregulation of the industry has caused a convergence in regulated and non-regulated returns over that time period. While the data do not suggest that utilities in states that have never undertaken deregulation have meaningfully different risk premiums, there are many ways to evaluate the "degree" of deregulatory activity that could be explored.

Another public policy-related factor could be a change in the nature of the rate base or of rate-making itself. Toward the beginning of our study period, most of the electric utilities were vertically integrated (i.e., in the business of both generation and transmission of power). Over time, generation became increasingly exposed to deregulation, while transmission and distribution of power have tended to remain regulated. To the extent that the portion of the rate base comprised of transmission and distribution assets has increased at the expense of generation assets, it may suggest a shift in the underlying risk profile of the assets being recognized by regulators. We note, for example, that public policy has tended to favor transmission investments with "incentive rates" in recent years in order to address a perceived relative lack of investment in transmission within the electric power sector. Our data, however, reveal the opposite. Based on data since 2000, there have been 172 transmission and distribution-only cases, out of 653 total cases. The average rate of return authorized in the transmission and distribution cases is approximately 60 basis points *lower* than those in vertically-integrated cases from the same period. These have been *state-*

level cases however. We note as deserving of further study that (interstate) electric transmission is regulated by FERC using a well-defined DCF approach instead of CAPM. The impact of having differing regulatory frameworks to set rates for assets that are functionally substantially identical remains an open question.

As for a change in the nature of rate-making itself, we note that the industry has tended to move from cost-of-service rate-making to performance-based ratemaking. If this shift, in an attempt to increase utility operating efficiency, has inadvertently raised the cost of equity capital through the use of incentive rates, it would be important to ascertain if the net cost-benefit balance has been positive. In general, there has been a lack of attention to the impact of regulatory changes on discount rates. The data on authorized returns on equity provides a unique dataset for such investigations.

5.3. Strategies for mitigating the growing premium

Our research does not necessarily imply that the rates of return authorized by regulators are too high, or otherwise necessarily inappropriate for utilities. An evaluation of whether these non-normative factors constitute a legitimate basis of rate of return determination deserves separate study. But if institutional or behavioral factors lead to departures from normative outcomes in setting rates of return on equity, then perhaps like Ulysses and the Sirens, regulators' hands should be "tied to the mast."

One notable jurisdictional difference in regulatory practice is between formulaic and judgment-based approaches to setting the cost of capital. In Canada, for example, formulaic approaches are more prevalent than in the United States (Villadsen and Brown, 2012). California also adjusts returns on equity for variations in bond yields beyond a "dead band," and the performance-based regulatory approaches in Mississippi and Alabama rely on formulaic cost of capital determination (Villadsen et al., 2017).

By pre-committing to a set formula (e.g., government bond rates plus *n* basis points) in lieu of holding adversarial hearings, regulators could minimize the potential for deviation from outcomes consistent with finance theory. Villadsen and Brown (2012) noted, for example, that then-recent rates set by Canadian regulators tended to be lower than those set by U.S. regulators despite nearly equivalent riskless rates of return. An intermediate approach would be to require regulators to calculate and present a formulaic result, but then allow them the discretion to authorize deviations from such a result when circumstances justify such departures. In such cases, regulators could avoid anchoring on past results, and instead anchor on a theoretically-justifiable return, before adjusting for any mitigating factors. If regulator judgment is impaired or subject to bias, then minimizing the influence of judgment by deferring to models may be prudent. In the end, we may observe simply that what regulators *should* do, what regulators *say* they're doing, and what regulators *actually* do may be three very different things.

Conflicts of interest

The authors declare that they have no conflict of interest.

Funding

This research did not receive any specific grant from funding agencies in the public, commercial, or not-for-profit sectors.

Acknowledgements

This paper is based on a portion of the first author's doctoral dissertation. The authors gratefully acknowledge the thoughtful comments and assistance received from Jay Apt, Tony Páez, Thomas Yu, Chad Schafer, participants at the Carnegie Mellon Electricity Industry Center's 2017 Advisory Committee Meeting, and two anonymous reviewers. All responsibility for any errors remains with the authors.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.enpol.2019.110891.

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EXHIBIT KRR-16

Energy Institute WP 329

Rate of Return Regulation Revisited

Karl Dunkle Werner and Stephen Jarvis

September 2022

Energy Institute at Haas working papers are circulated for discussion and comment purposes. They have not been peer-reviewed or been subject to review by any editorial board. The Energy Institute acknowledges the generous support it has received from the organizations and individuals listed at https://haas.berkeley.edu/energy-institute/about/funders/.

Rate of Return Regulation Revisited

Karl Dunkle Werner and Stephen Jarvis *

September 2022

Abstract

Utility companies recover their capital costs through regulator-approved rates of return on debt and equity. In the US the costs of risky and risk-free capital have fallen dramatically in the past 40 years, but utility rates of return have not. Using a comprehensive database of utility rate cases dating back to the 1980s, we estimate that the current average return on equity could be around 0.5–5.5 percentage points higher than various benchmarks and historical relationships would suggest. We discuss possible mechanisms and show that regulated rates of return respond more quickly to increases in market measures of the cost of capital than they do to decreases. We then provide empirical evidence that higher regulated rates of return lead utilities to own more capital – the Averch–Johnson effect. A 1 percentage point rise in the return on equity increases new capital investment by about 5%. Overall we find that consumers may be paying $2–20 billion per year more than they would otherwise if rates of return had fallen in line with capital market trends.

JEL Codes: Q4, L5, L9

Keywords: Utility, Rate of Return, Regulation, Electricity, Natural Gas, Capital Investment

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1 Introduction

In the two decades from 1997 to 2017, real annual capital spending on electricity distribution infrastructure by major utilities in the United States has doubled (EIA 2018a). Over the same time period annual capital spending on electricity transmission infrastructure increased by a factor of seven (EIA 2018b). The combined total is now more than $50 billion per year. This trend is expected to continue. Bloomberg New Energy Finance predicts that between 2020 and 2050, North and Central American investments in electricity transmission and distribution will likely amount to $1.6 trillion, with a further $1.7 trillion for electricity generation and storage (Henbest et al. 2020).[1]

These large capital investments could be due to the prudent actions of utility companies modernizing an aging grid. They may also be a necessary response to the clean energy transition underway in much of the gas and electric utility sector. However, it is noteworthy that over recent years, utilities have earned sizeable regulated rates of return on their capital assets, particularly when set against the unprecedented low interest rate environment post-2008. When the economy-wide cost of capital fell, utilities' regulated rates of return did not fall nearly as much. This gap raises the prospect that at least some of the growth in capital spending could be driven by utilities earning excess regulated returns.

Utilities over-investing in capital assets as a result of excess regulated returns is an age old concern in the sector (Averch and Johnson 1962). The resulting costs from "gold plating" are then passed on to consumers in the form of higher bills. Capital markets and the utility industry have undergone significant changes over the past 50 years since the early studies of utility capital ownership (Joskow 1972, 1974). In this paper we use new data to revisit these issues. We do so by exploring

1. North and Central American generation/storage are reported directly. Grid investments are only reported globally, so we assume the ratio of North and Central America to global is the same for generation/storage as for grid investments.

three main research questions. First, to what extent are utilities being allowed to earn excess returns on equity by their regulators? Second, how has this return on equity affected utilities' capital investment decisions? Third, what impact has this had on the costs paid by consumers?

To answer our research questions, we use data on the utility rate cases of all major electricity and natural gas utilities in the United States spanning the past four decades (Regulatory Research Associates 2021). We combine this with a range of financial information on credit ratings, corporate borrowing, and market returns. To examine possible sources of over-investment in more detail we also incorporate data from annual regulatory filings on individual utility capital spending.

We start our analysis by estimating the size of the gap between the allowed rate of return on equity (RoE) that utilities earn and some measure of the cost of equity they face. A central challenge here, both for the regulator and for the econometrician, is estimating the cost of equity. We proceed by considering a range of approaches to simulating the actual cost of equity based on available measures of capital market returns, the capital asset pricing model (CAPM) and a comparison with regulatory decisions in the United Kingdom. None of these are perfect comparisons; but taken together, our various estimation approaches result in a consistent trend of excess rates of return. These results are necessarily uncertain, and depending on our chosen benchmark the premium ranges from 0.5 to 5.5 percentage points. Importantly though, even our most conservative benchmarks come in below the allowed rates of return on equity that regulators set today.

The existence of a persistent gap between the return on equity that utilities earn and some measure of the cost of capital they face could have a number of explanations. Recent work by Rode and Fischbeck (2019) ruled out a number of financial reasons we might see increasing RoE spreads, such as changes to utilities' debt/equity ratio, asset-specific risk, or the market's overall risk premium. This leaves them looking for other explanations – for example, they highlight that regulators seem to follow some ad-hoc approaches that make them reluctant to set RoE below a nominal 10%. Azgad-Tromer and Talley (2017) also find that allowed rates of return diverge significantly from what would be expected by a standard CAPM approach. They point to a range of non-financial factors that may play an important role, including political goals and regulatory capture. Using data from a field experiment they show that providing finance training to regulatory staff does have a moderate effect on moving rates of return closer to standard asset pricing predictions.

These insights point to the broader challenges inherent in the ratemaking process. Regulators face an information asymmetry with the utilities they regulate when determining whether costs are prudent and necessary (Joskow, Bohi, and Gollop 1989). Utilities have a clear incentive to request rate increases when their costs go up, but do not have much incentive to request a rate decrease when their costs go down. If regulators are too deferential to the demands of the utilities they regulate – perhaps due to a insufficient expertise or regulatory capture (Dal Bó 2006) – we would expect rates to become detached from underlying costs.

We explore this issue by drawing on the literature on asymmetric price adjustments. It has been documented in various industries that positive shocks to firms' input costs can feed through into prices faster than negative shocks (Bacon 1991; Borenstein, Cameron, and Gilbert 1997; Peltzman 2000). This is the so-called "rockets and feathers" phenomenon. We test this hypothesis by estimating a vector error correction model for the relationship between utilities' return on equity and some benchmark measures of the cost of capital (e.g. US Treasury Bond yields). Here we do indeed find evidence of asymmetric adjustment. Increases to the benchmark cost of capital lead to rapid rises in utilities' return on equity, while decreases lead to less rapid falls.

Excess regulated returns on equity will distort the incentives for utilities to invest in capital. To consider the change in the capital base, we turn to a regression analysis.

Here we aim to identify how a larger RoE gap translates into over-investment in capital. Identification is challenging in this setting, so we again employ several different approaches, with different identifying assumptions. In addition to a basic within-utility comparison, we examine instrumental variables. For our preferred approach we draw on the intuition that after a rate case is decided, the utility's RoE is *fixed* at a particular nominal percentage for several years. The cost of capital in the rest of the economy, and therefore the cost of equity for the utility, will shift over time. We use these shifts in the timing and duration of rate cases as an instrument for changes in the RoE gap. We also examine a second instrument that exploits an apparent bias of regulators rounding the RoE values they approve, though ultimately this instrument is too weak for us to use.

Across the range of specifications used, we find a broadly consistent picture. In our preferred specification we find that increasing the RoE gap by one percentage point leads to a five percent increase in the approved change in the rate base. We observe similar effects for the overall size of the approved rate base.

Combining our measures of the RoE gap with the distortions to capital investment, we estimate the cost to consumers from excess rates of return reached around $2–20 billion per year by 2020, with the majority of these costs coming from the electricity sector. These costs have important distributional effects, representing a sizeable transfer from consumers to investors. Increasing the price of electricity also has important implications for environmental policy and efforts to encourage electrification (Borenstein and Bushnell 2022).

2 Background

Electricity and natural gas utility companies are typically regulated by government utility commissions, which allow the companies a geographic monopoly and, in exchange, regulate the rates the companies charge. These utility commissions are state-level regulators in the US. They set consumer rates and other policies to allow investor-owned utilities (IOUs) a designated rate of return on their capital investments, as well as recovery of non-capital costs. This rate of return on capital is almost always set as a nominal percentage of the installed capital base. For instance, with an installed capital base worth $10 billion and a rate of return of 8%, the utility is allowed to collect $800 million per year from customers for debt service and to provide a return on equity to shareholders. State utility commissions typically update these nominal rates every 3–6 years.

Utilities own physical capital (power plants, gas pipelines, repair trucks, office buildings, etc.). The capital depreciates over time, and the set of all capital the utility owns is called the rate base (the base of capital that rates are calculated on). Properly accounting for depreciation is far from straightforward, but we will not focus on that challenge in this paper. This capital rate base has an opportunity cost of ownership: instead of buying capital, that money could have been invested elsewhere. IOUs fund their operations through issuing debt and equity, typically about 50%/50%. For this paper, we focus on common stocks (utilities issue preferred stocks as well, but those form a very small fraction of utility financing). The weighted average cost of capital is the weighted average of the cost of debt and the cost of equity.

Utilities are allowed to set rates to recover all of their costs, including this cost of capital. For some expenses, like fuel purchases, it's easy to calculate the companies' costs. For others, like capital, the state public utilities commissions are left trying to approximate the capital allocation at a cost that competitive capital markets would provide if the utility had been a competitive company rather than a regulated monopoly. The types of capital utilities own, and their opportunities to add capital to their books, varies depending on market and regulatory conditions. Utilities that are vertically integrated might own a large majority of their own generation, the transmission lines, and the distribution infrastructure. Other utilities are "wires only," buying power from independent power producers and transporting it over their lines. Natural gas utilities are typically pipeline only – the utility doesn't own the gas well or processing plant.

In the 1960s and 70s, state public utilities commissions (PUCs) began adopting automatic fuel price adjustment clauses. Rather than opening a new rate case, utilities used an established formula to change their customer rates when fuel prices changed. The same automatic adjustment has generally not been the norm for capital costs, despite large swings in the nominal cost of capital over the past 50 years. A few jurisdictions have introduced limited automatic updating for the cost of equity, and we discuss those approaches in more detail in section 4.1, where we consider various approaches of estimating the RoE gap.

Regulators typically employ a "test year", a single 12-month period in the past or future that will be used as the basis for the rate case analysis. Expenses and capital costs in this test year, except those with automatic update provisions, are the values used for the entire rate case.

The cost of debt financing is easier to estimate than the cost of equity financing. For historical debts, it is sufficient to use the cost of servicing those debts. For forward-looking debt issuance, the cost is estimated based on the quantity and cost of expected new debt. Issues remain for forward looking decisions – e.g. what will bond rates be in the future test year? – but these are *relatively* less severe. In our data, we see both the utilities' requested and approved return on debt. It's notable that the requested and approved rates are very close for debt, and much farther apart for equity.

The cost of equity financing is more challenging. Theoretically, it's the return shareholders require in order to invest in the utility. The Pennsylvania Public Utility Commission's ratemaking guide notes this difficulty (Cawley and Kennard 2018):

> Regulators have always struggled with the best and most accurate method to use in applying the [*Federal Power Commission v. Hope Nat-*

> *ural Gas Company* (1944)] criteria. There are two main conceptual approaches to determine a proper rate of return on common equity: "cost" and "the return necessary to attract capital." It must be stressed, however, that no single one can be considered the only correct method and that a proper return on equity can only be determined by the exercise of regulatory judgment that takes all evidence into consideration.

Unlike debt, where a large fraction of the cost is observable and tied to past issuance, the cost of equity is the ongoing, forward-looking cost of holding shareholders' money. Put differently, the RoE is applied to the entire rate base – unlike debt, there's typically no notion of paying a specific RoE for specific stock issues.

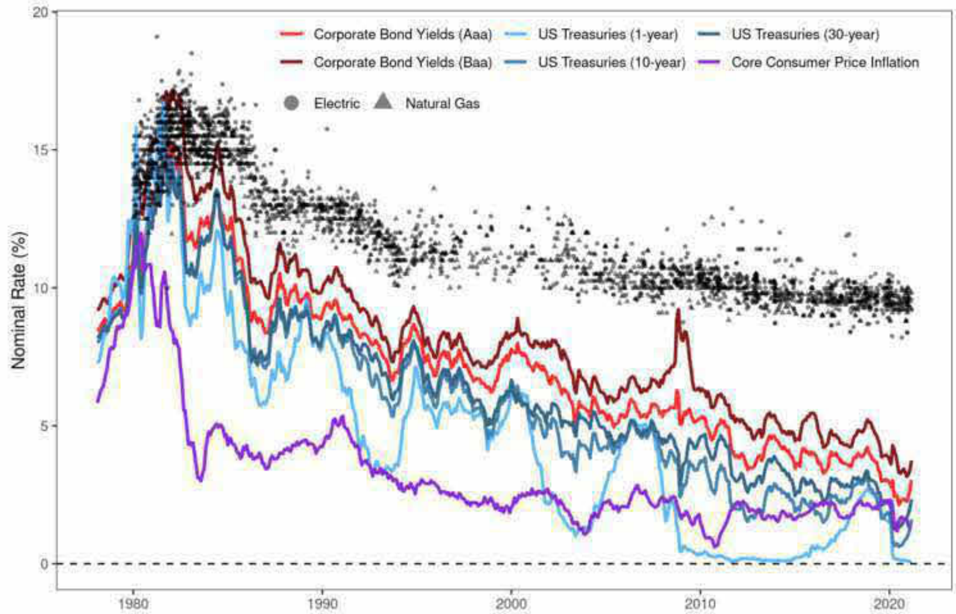
Regulators employ a mixture of models and subjective judgment. Typically, these approaches involve benchmarking against other US utilities (and often utilities in the same geographic region). There are advantages to narrow benchmarking, but when market conditions change and everyone is looking at their neighbors, rates will update very slowly.

In Figure 1 we plot the approved return on equity over 40 years, with various risky and risk-free rates for comparison. The two panels show nominal and real rates.[2] Consistent with a story where regulators adjust slowly, approved RoE has fallen slightly (in both real and nominal terms), but much less than other costs of capital. This price stickiness by regulators also manifests in peculiarities of the rates regulators approve. For instance, Rode and Fischbeck (2019) note an apparent reluctance from to set RoE below a nominal 10%.

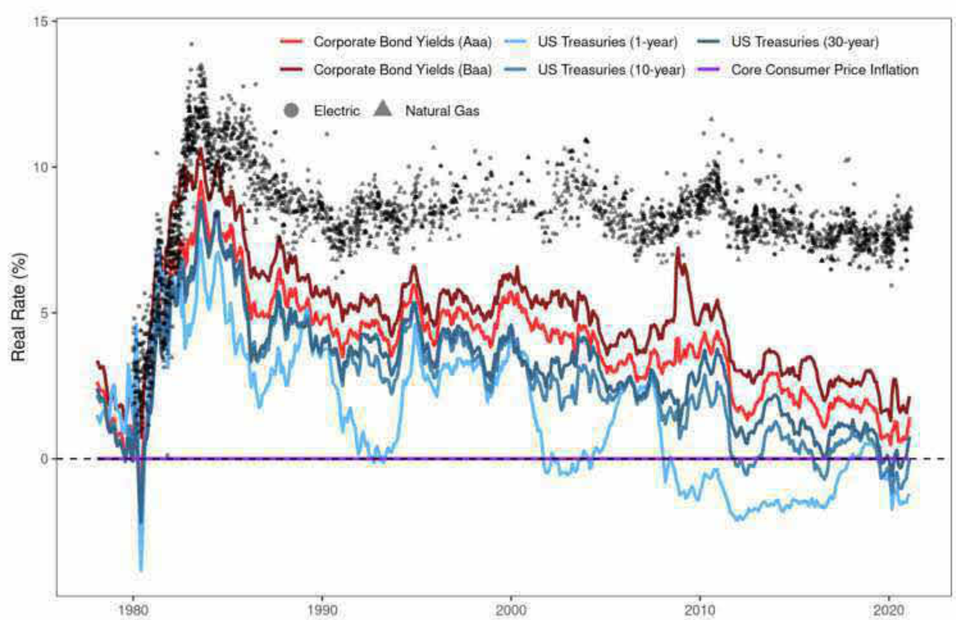
That paper, Rode and Fischbeck (2019), is the closest to ours in the existing literature. The authors use the same rate case dataset we do, and note a similar widening of the spread between the approved return on equity and 10-year Treasury rates. That paper, unlike ours, dives into the financial modeling, using the standard

2. We calculate real values by subtracting the monthly core CPI.

Figure 1: Return on Equity and Financial Indicators



(a) Nominal



(b) Real

Notes: These figures show the approved return on equity for investor-owned US electric and natural gas utilities. Each dot represents the resolution of one rate case. Real rates are calculated by subtracting core CPI. Between March 2002 and March 2006 30-year Treasury rates are extrapolated from 1- and 10-year rates (using the predicted values from a regressing the 30-year rate on the 1- and 10-year rates).
SOURCES: Regulatory Research Associates (2021), Moody's (2021a, 2021b), Board of Governors of the Federal Reserve System (2021a, 2021b, 2021c), and US Bureau of Labor Statistics (2021).

capital asset pricing model (CAPM) to examine potential causes of the increase the RoE spread. In contrast, we consider a wider range of financial benchmarks (beyond 10-year Treasuries) and ask more pointed questions about the implications of this growing RoE gap for utilities' investment decisions and costs for consumers.

Using CAPM, Rode and Fischbeck (2019) rule out a number of financial reasons we might see increasing RoE spreads. Possible reasons include utilities' debt/equity ratio, the asset-specific risk (CAPM's β), or the market's overall risk premium. None of these are supported by the data. A pattern of steadily increasing debt/equity could explain an increasing gap, but debt/equity has fallen over time. Increasing asset-specific risk could explain an increasing gap, but asset risk has (largely) fallen over time. An increasing market risk premium could explain an increased spread between RoE and riskless Treasuries, but the market risk premium has fallen over time.

Prior research has highlighted the importance of macroeconomic changes, and that these often aren't fully included in utility commission ratemaking (Salvino 1967; Strunk 2014). Because rates of return are typically set in fixed nominal percentages, rapid changes in inflation can dramatically shift a utility's real return. This pattern is visible in figure 1 in the early 1980s. Until 2021, inflation has been lower and much more stable.

Many authors have written a great deal about modifying the current system of investor-owned utilities. Those range from questions of who pays for fixed grid costs to the role of government ownership or securitization (Borenstein, Fowlie, and Sallee 2021; Farrell 2019). For this project, we assume the current structure of investor-owned utilities, leaving aside other questions of how to set rates across different groups of customers or who owns the capital.

3 Data

To answer our research questions, we use a database of resolved utility rate cases from 1980 to 2021 for every electricity and natural gas utility that either requested a nominal-dollar rate base change of $5 million or had a rate base change of $3 million authorized (Regulatory Research Associates 2021). Summary statistics on these rate cases can be seen in Table 1. Our primary variables of interest are the rates of return and the rate base. [3] We also merge data on annual number of customers, quantity supplied and sales revenue for the electric utilities in our sample (US Energy Information Administration 2022).

We transform this panel of rate case events into an unbalanced utility-by-month panel, filling in the rate base and rate of return variables in between each rate case. There are some mergers and splits in our sample, but our SNL data provider lists each company by its present-day (2021) company name, or the company's last operating name before it ceased to exist. With this limitation in mind, we construct our panel by (1) not filling data for a company before its first rate case in a state, and (2) dropping companies five years after their last rate case. In contexts where a historical comparison is necessary, but the utility didn't exist in the benchmark year, we use average of utilities that did exist in that state, weighted by rate base size.

We match with data on S&P credit ratings, drawn from SNL's *Companies (Classic) Screener* (2021) and WRDS' *Compustat S&P legacy credit ratings* (2019). Most investor-owned utilities are subsidiaries of publicly traded firms. We use the former data to match as specifically as possible, first same-firm, then parent-firm, then same-ticker. We match the latter data by ticker only. Then, for a relatively small number of firms, we fill forward.[4] Between these two sources, we have ratings data available

3. We focus here on proposed and approved rates of return. It is possible that utility's actual rate of return or return on equity might differ from the approved level. In general though, actual returns do tend to track allowed returns quite closely.

4. When multiple different ratings are available, e.g. different ratings for subsidiaries trading

Table 1: Summary Statistics

Characteristic	N	Electric[1]	Natural Gas[1]
Rate of Return Proposed (%)	3,324	9.95 (1.98)	10.07 (2.07)
Rate of Return Approved (%)	2,813	9.59 (1.91)	9.53 (1.95)
Return on Equity Proposed (%)	3,350	13.22 (2.69)	13.06 (2.50)
Return on Equity Approved (%)	2,852	12.38 (2.40)	12.05 (2.24)
Return on Equity Proposed Spread (%)	3,350	6.72 (2.18)	6.95 (1.99)
Return on Equity Approved Spread (%)	2,852	5.62 (2.27)	5.68 (2.10)
Return on Debt Proposed (%)	3,247	7.48 (2.11)	7.47 (2.16)
Return on Debt Approved (%)	2,633	7.54 (2.06)	7.44 (2.16)
Equity Funding Proposed (%)	3,338	45 (7)	48 (7)
Equity Funding Approved (%)	2,726	44 (7)	47 (7)
Customers (thous)	1,177	693 (929)	NA (NA)
Quantity (TWh)	1,177	17 (21)	NA (NA)
Revenue ($ mn)	1,177	1,470 (2,086)	NA (NA)
Rate Base Increase Proposed ($ mn)	3,686	84 (132)	24 (41)
Rate Base Increase Approved ($ mn)	3,672	40 (84)	12 (25)
Rate Base Proposed ($ mn)	2,366	2,239 (3,152)	602 (888)
Rate Base Approved ($ mn)	1,992	2,122 (2,991)	583 (843)
Case Length (yr)	3,364	3.11 (3.97)	3.01 (3.34)
Rate Case Duration (mo)	3,713	9.1 (5.1)	8.1 (4.3)

[1]Mean (SD)

Notes: This table shows the rate case variables in our rate case dataset. Values in the Electric and Natural Gas columns are means, with standard deviations in parenthesis. Approved values are approved in the final determination, and are the values we use in our analysis. Some variables are missing, particularly the approved rate base. The RoE spread in this table is calculated relative to the 10-year Treasury rate.
SOURCE: Regulatory Research Associates (2021), US Energy Information Administration (2022), and author calculations.

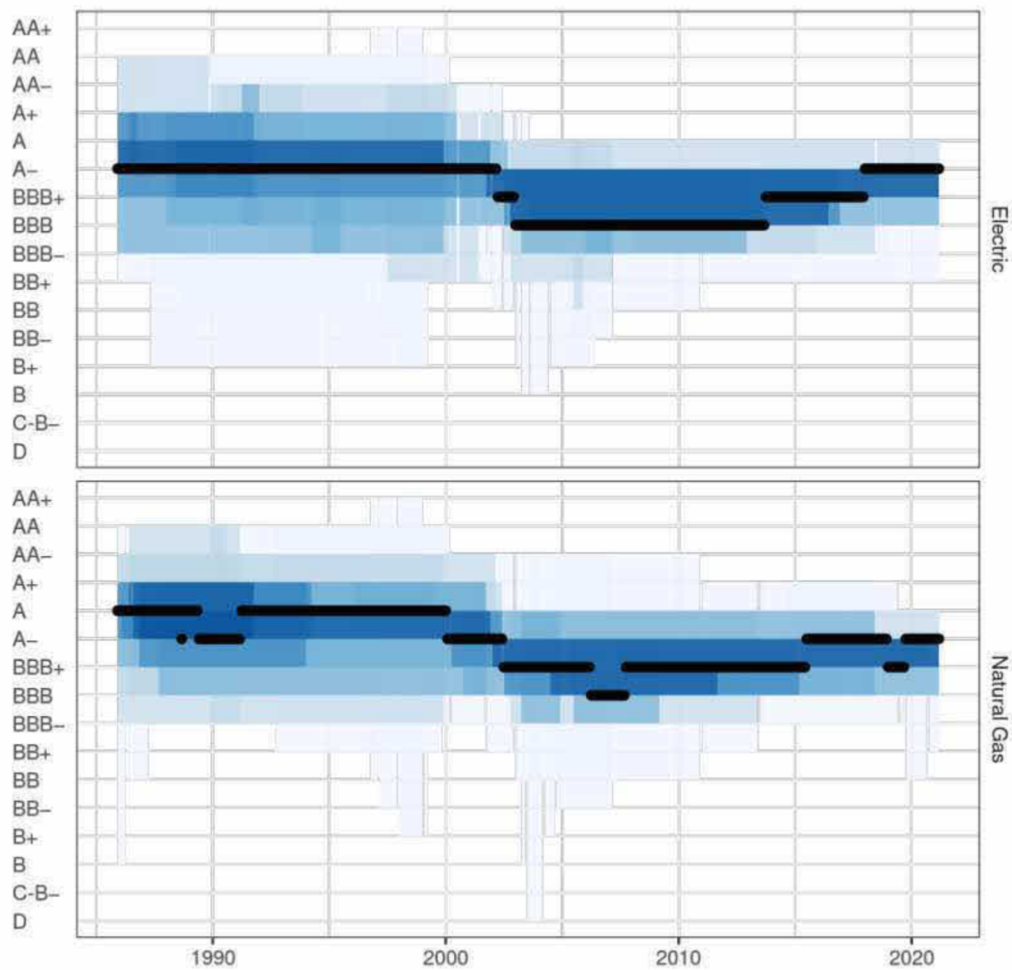
from December 1985 onward. Approximately 80% of our utility–month observations are matched to a rating. Match quality improves over time: approximately 89% of observations after 2000 are matched.

These credit ratings have changed little over 35 years. In figure 2 we plot the median (in black) and various percentile bands (in shades of blue) of the credit rating for utilities active in each month. We note that the median credit rating has

under the same ticker, we take the median rating. We round down (to the lower rating) in the case of an even number of ratings.

seen modest movements up and down over the past decades. The distribution of ratings is somewhat more compressed in 2021 than in the 1990s. While credit ratings are imperfect, we would expect rating agencies to be aware of large changes in riskiness.[5] Instead, the median credit rating for electricity utilities is A−, as it was for all of the 1990s. The median credit rating for natural gas utilities is also A−, down from a historical value of A.

Figure 2: Credit ratings have changed little in 35 years



NOTE: Black lines represent the median rating of the utilities active in a given month. We also show bands, in different shades of blue, that cover the 40–60 percentile, 30–70 percentile, 20–80 percentile, 10–90 percentile, and 2.5–97.5 percentile ranges. (Unlike later plots, these *are not* weighted by rate base.) Ratings from C to B– are collapsed to save space.
SOURCE: *Companies (Classic) Screener* (2021) and *Compustat S&P legacy credit ratings* (2019).

5. For utility risk to drive up the firms' cost of equity but not affect credit ratings, one would need to tell a very unusual story about information transmission or the credit rating process.

Beyond credit ratings, we also use various market rates pulled from FRED. These include 1-, 10-, and 30-year Treasury yields, the core consumer price index (CPI), bond yield indexes for corporate bonds rated by Moody's as Aaa or Baa, as well as those rated by S&P as AAA, AA, A, BBB, BB, B, and CCC or lower.[6]

Matching these two datasets – rate cases and macroeconomic indicators – we construct the timeseries shown in Figure 1. A couple of features jump out, as we mentioned in the introduction. The gap between the approved return on equity and other measures of the cost of capital have increased substantially over time. At the same time, the return on equity has decreased over time, but much more slowly than other indicators. This is the key stylized fact that motivates our examination of the return on equity that utilities earn and the implications this may have for their incentives to invest in capital and the costs they pass on to consumers.

4 Empirical Strategy

4.1 The Return on Equity Gap

Knowing the size of the return on equity (RoE) gap is a challenge, and we take a couple of different approaches. None are perfect, but collectively, they shed light on the question.

4.1.1 Benchmarking to a Baseline Spread

We first consider a benchmark index of corporate bond yields. The idea here is to ask: what would the RoE be today if the average spread against corporate bond yields had not changed since some baseline date? Here we compare all utilities to the corporate bond index that is closest to that utility's own, contemporaneous debt

6. Board of Governors of the Federal Reserve System (2021a, 2021b, 2021c), US Bureau of Labor Statistics (2021), Moody's (2021a, 2021b), and Ice Data Indices, LLC (2021b, 2021a, 2021f, 2021d, 2021c, 2021g, 2021e).

rating. [7] To calculate the RoE gap we first find the spread between the approved return on equity and the bond index rate for each utility in each state in a baseline period. We then take this spread during the baseline period and apply it to the future evolution of the bond index rate to get an estimate of the baseline RoE. The RoE gap is the difference between a given utility's allowed return on equity at some point in time and this baseline RoE.

The choice of the baseline period is also worth considering here. Throughout our analysis we use January 1995 as the baseline period. The date chosen determines where the gap between utilities' RoE and baseline RoE is zero. Changing the baseline date will shift the overall magnitude of the gap. As long as the baseline date isn't in the middle of a recession, our qualitative results don't depend strongly on the choice. Stated differently, the baseline year determines when the average gap is zero, but this is a constant shift that does not affect the overall trend. While January 1995 is not special, we note that picking a much more recent baseline would imply that utilities were substantially under-compensated for their cost of equity for many continuous years.

Our second measure adopts a similar approach to the first but benchmarks against US Treasuries. The idea here is to ask: what would the RoE be today if the average spread against US Treasuries had not changed since some baseline date? This measure is calculated in exactly the same way as our first approach except the spread is measured against the 10-year Treasury bond yield in the baseline period, rather than the relevant corporate bond index.

Our third measure continues with using US Treasuries but does so using an RoE update rule. This rule is consistent with the approach taken by the Vermont

7. We also examined a comparison against a single Moodys' Baa corporate bond index. Moody's Baa is approximately equivalent to S&P's BBB, a rating equal to or slightly below most of the utilities in our data (see figure 2). This avoids issues where utilities' bond ratings may be endogenous to their rate case outcomes. Using a single index also faces fewer data quality challenges. The findings using the single Moody's Baa bond index are broadly equivalent to those using a same rated bond index and our later approach using US Treasuries.

PUC, and similar approaches have been used in the past in California and Canada. Relative to some baseline period the automatic update rule adjusts the RoE at half the rate that the yield on the 10-year US Treasury bond changes over that time period. [8] The Vermont PUC uses 10-year US Treasuries and set the baseline period as December 2018, for their plan published in June 2019. (*Green Mountain Power: Multi-Year Regulation Plan 2020–2022* 2020). In our case we also use 10-year Treasuries and set the baseline to January 1995. We simulate the gap between approved RoE and what RoE would have been if every state's utilities commission followed this rule from 1995 onward. [9]

4.1.2 Benchmarking to the Capital Asset Pricing Model

Our fourth and fifth measures draw directly on the Capital Asset Pricing Model (CAPM) approach. The CAPM approach is widely used by regulators to support their decisions on utility equity returns, alongside other methods such as Discounted Cash Flow (DCF). In principle the CAPM provides an objective way to quantify the expected returns for an asset given the risk of that asset and the returns available in the market over-and-above some risk-free rate. In practice its application remains open to a significant degree of subjective interpretation, in large part through the choice of values for its key parameters. As such, even CAPM calculations can form part of the negotiation process between regulators and utilities, with the latter having a clear incentive to lobby for assumptions that result in the CAPM producing higher estimates of the cost of equity.

We calculate predictions of the equity returns for each utility using the standard CAPM formula.

$$RoE = R_f + (\beta \times MRP)$$

8. Define RoE' as the baseline RoE, B' as the baseline 10-year Treasury bond yield, and B_t as the 10-year Treasury bond yield in year t. RoE in year t is then: $RoE_t = RoE' + (0.5 \times (B_t - B'))$

9. Pre-1995 values are not particularly meaningful, but we can calculate them with the same formula.

Here R_f is the risk-free rate, MRP is the market risk premium and β is the equity beta for the asset in question – namely each utility in our sample. Our assumed values for each of these parameters are broadly in line with published data (Damodaran 2022a) and values used by regulators in the UK, Europe, Australia and at the federal level for the US (Australian Energy Regulator 2020; Economic Consulting Associates 2020; UK Regulatory Network 2020). The parameter values used by state PUCs in the US tend to fall at the higher end of the range we examine. We calculate the RoE gap by taking the contemporaneous difference between our CAPM estimate of RoE and each utility's allowed RoE.

Risk-free rate

The risk-free rate, R_f, is intended to capture the base level of returns from an effectively zero risk investment. Yields on government bonds are the common source for this information, although practitioners can differ over the choice of maturity (e.g. 10-year or 30-year) and the use of forecast future yields instead of past or current rates. These decisions can significantly affect the final cost of equity. [10] We use the contemporaneous yield on US Treasury Bonds for our measure of the risk-free rate. In our "low" case we use 10-year Treasuries and in our "high" case we use 30-year Treasuries.

Market risk premium

The market risk premium, MRP, captures the difference between the expected equity market rate of return and the risk-free rate. [11] This is generally calculated by taking the average of the difference in returns for some market-wide stock index and the returns for the risk-free rate. While this appears relatively straightforward, the final value can vary significantly depending on numerous factors. These can include: the choice of stock market index (e.g. S&P 500, Dow Jones, Wilshire 5000

10. For instance, in January 2018 the current yield on 10-year US Treasury Bonds was 2.58%, the average yield from the past 2 years was 2.09%, and the forecast yield from Wolters Klewer (2022) for the next 2 years was 2.97%.

11. $MRP = R_m - R_f$, where R_m is the market return and R_f is the risk-free return.

etc.); the choice of averaging period (e.g. previous 10, 20, 50 years etc.); the return frequency (e.g. monthly, quarterly or annual returns), and the method of averaging (arithmetic, geometric). These decisions can significantly affect the final cost of equity. [12] To capture the uncertainty in the market risk premium, in our "low" case we assume a constant MRP of 6 percent and in our "high" case we assume a constant MRP of 8 percent.

Beta

A firm's equity beta, β, is a measure of systematic risk and thus captures the extent to which the returns of the firm in question move in line with overall market returns. [13] Regulated firms like gas and electricity utilities are generally viewed as low risk, exhibiting lower levels of volatility than the market as a whole. The calculation of beta is subject to many of the same uncertainties mentioned above, including: the choice of stock market index; the choice of calculation period, and the return frequency.

It is also common to take beta estimates from existing data vendors such as Merrill Lynch, Value Line and Bloomberg. The choice of beta depends on the bundle of comparable firms used and how they are averaged. Furthermore, these vendors generally publish beta values that incorporate the so-called Blume adjustment to deal with concerns about mean reversion. [14] While plausible for many non-regulated firms, its applicability to regulated firms like utilities has been questioned (Michelfelder and Theodossiou 2013). Because utilities generally have betas below one the adjustment serves to increase beta and thus increase the estimated cost of equity produced by the CAPM calculation.

Lastly, the decision on setting beta is complicated by the fact that betas calculated

12. For instance, in January 2018 using annual returns for the S&P 500 compared to the 10-year US Treasury Bond and taking the arithmetic average over the past 5, 25 and 75 years produces market risk premiums of 14.8%, 5.2% and 7.3% respectively (Damodaran 2022b).

13. Beta is calculated by estimating the covariance of the returns for the firm in question, R_i, and the market returns, R_m, and then dividing by the variance of the market returns: $\beta = \frac{Cov(R_i,R_m)}{Var(R_m)}$

14. The Blume Adjustment equation is: $\beta_{adjusted} = 0.333(1) + 0.667(\beta)$

using observed stock returns are dependent on each firm's debt holdings and tax rate, which may differ from the particular utility being studied. To deal with this, an unlevered beta can be estimated and then the corresponding levered beta can be calculated for a specific debt-to-equity ratio, D/E, and tax rate, τ. [15] Here we take τ to be the federal marginal corporate tax rate and we can directly observe the debt-to-equity ratio, D/E, in our data.

To capture the uncertainty in beta, in our "low" case we assume a constant $beta_{unlevered}$ of 0.3 and in our "high" case we assume a constant $beta_{unlevered}$ of 0.5. This generally produces levered betas ranging from 0.6 to 0.9.

4.1.3 Benchmarking to UK utilities

Finally, our sixth measure involves benchmarking against allowed returns on equity for gas and electric utilities in the United Kingdom. Here we consider the contemporaneous gap in nominal allowed RoE between the US and UK. Of course many things are different between these countries, and it's not fair to say all US utilities should adopt UK rate making, but we think this benchmark provides an interesting comparison. The data on UK RoE are taken from various regulatory reports published by the Office of Gas and Electricity Markets (Ofgem). We were able to find information on allowed rates of return dating back to 1996. The relevant disaggregation into return on debt and return on equity was more readily available for electric utilities over this entire time period. For natural gas utilities we have this information from 2013 onwards. Importantly, UK rates are set in real terms and so we converted to nominal terms using the inflation indexes cited by the UK regulator.

15. The Hamada equation relates levered to unlevered beta as follows: $\beta = \beta_{unlevered} \times \left[1 + (1-\tau)\frac{D}{E}\right]$

4.2 Asymmetric Adjustment

The existence of a persistent gap between the return on equity that utilities earn and various measures of the cost of capital they face could have a number of explanations. One we examine here focuses on whether regulators are more responsive to the demands of the utilities they regulate than to pressures from consumer advocates. To do so we draw on the literature on asymmetric price adjustments.

It has been documented in many industries that positive shocks to firms' input costs can feed through into prices faster than negative shocks. This has been most extensively studied in the gasoline sector – see Kristoufek and Lunackova (2015) and Perdiguero-García (2013) for reviews of the literature. Building on early work by Bacon (1991) and Borenstein, Cameron, and Gilbert (1997), there are now a wealth of studies examining how positive shocks to crude oil prices lead to faster increases in retail gasoline prices than negative shocks to crude oil prices lead to decreases in retail gasoline prices. This is the so-called "rockets and feathers" phenomenon. A range of explanations for this have been explored, most notably tacit collusion and market power or the dynamics of consumer search.

In our setting we do observe that a change in some benchmark index (e.g. US Treasuries or corporate bonds) appears to feed through into the allowed return on equity for utilities. This can be seen most clearly in Figure 1 where relatively short-run spikes in US Treasuries or corporate bond yields correlate strongly with corresponding spikes in allowed returns on equity. We have also already discussed the sluggish pace at which allowed returns on equity have come down over the longer-term when compared to various benchmark measures of the cost of capital. It therefore seems plausible to think that this relationship may function differently depending on whether it is a positive or a negative shock. To test this we follow the literature on asymmetric price adjustments and estimate a vector error correction model. First we estimate the long-run relationship between the return on equity for utility i in period t ($RoE_{i,t}$) and a lagged benchmark index of the cost of capital ($Index_{i,t-1}$). [16]

$$RoE_{i,t} = \beta\, Index_{i,t-1} + \varepsilon_{i,t}$$

In the second step we then run a regression of the change in RoE on three sets of covariates: (1) m lags of the past changes in RoE, (2) n lags of the past change in the index, and (3) the residuals from the long-run relationship, $\hat{\varepsilon}_{i,t}$, lagged from the previous period. To examine potential asymmetric adjustment, each of these three sets of covariates is split into positive and negative components to allow the coefficients for positive changes to differ from the coefficients for negative changes.

$$\begin{aligned}\Delta RoE_{i,t} = &\sum_{j=1}^{m} \alpha_j^{+} \Delta RoE_{i,t-j}^{+} + \sum_{j=1}^{m} \alpha_j^{-} \Delta RoE_{i,t-j}^{-} + \\ &\sum_{j=1}^{n} \gamma_j^{+} \Delta Index_{i,t-j}^{+} + \sum_{j=1}^{n} \gamma_j^{-} \Delta Index_{i,t-j}^{-} + \\ &\theta^{+} \hat{\varepsilon}_{i,t-1}^{+} + \theta^{-} \hat{\varepsilon}_{i,t-1}^{-} + v_{i,t}\end{aligned}$$

The key coefficients of interest are the θ coefficients on the residual error correction terms. If these coefficients are statistically different from one another, we take this as evidence of asymmetric adjustment. [17]

4.3 Rate Base Impacts

Next, we turn to the rate base the utilities own. To the extent a utility's approved RoE is higher than their actual cost of equity, they will have a too-strong incentive to have capital on their books. In this section, we investigate the change in rate base

16. It is notable that the coefficient estimates we find for β are generally close to the adjustment factors used in the automatic update rules employed by the Vermont PUC and California PUC (discussed earlier). This suggest these rules appear to largely formalize existing trends.

17. That is, our null hypothesis is $\theta^{+} = \theta^{-}$.

utilities request and receive. The change is a flow variable while the total rate base is the stock of all previous rate base changes. It includes both new investment and depreciation of existing assets. We primarily focus on the effect on the *change* in the rate base, rather than the entire rate base, because the former is actively decided in each rate case and the data is more complete. However, we observe similar effect sizes when looking at the entire rate base. We consider both the requested change and the approved change, though the approved value is our preferred specification. We estimate $\hat{\beta}$ from the following, where we regress the rate base increase (RBI) on the estimated RoE gap, various controls, and fixed effects.

$$\log(RBI_{i,t}) = \beta RoE_{i,t}^{gap} + \gamma X_{i,t} + \theta_i + \lambda_t + \epsilon_{i,t} \tag{1}$$

where an observation is a utility rate case for utility i in year-of-sample t. The dependent variable, $RBI_{i,t}$, is the increase in the rate base, and we take logs.[18] The ideal independent variable would be the gap between the allowed RoE and the utilities' costs of equity. Because the true value is unobservable, we use $RoE_{i,t}^{gap}$, the gap between the allowed RoE and the baseline RoE. Unlike section 4.1, for this analysis we care about differences in the gap between utilities or over time, but do not care about the overall magnitude of the gap. For ease of implementation, we begin by considering the gap as the spread between the approved rate of return and the 10-year Treasury bond yield. We do not expect the actual cost of equity to be equal to the 10-year Treasury yield, but our fixed effects account for any constant differences. We calculate $RoE_{i,t}^{gap}$ by taking the difference between the allowed RoE and the average of the time-varying baseline RoE, over the D years the rate case is in place.

$$RoE_{i,t}^{gap} = RoE_{i,t}^{allowed} - \frac{1}{D}\sum_{t}^{t+D} RoE_{i,t}^{benchmark} \tag{2}$$

18. Cases where the rate base shrinks are rare; we drop these cases.

4.3.1 Fixed Effects Specifications

Our goal is to make causal claims about $\hat{\beta}$, so we are concerned about omitted variables that are correlated with both the estimated RoE gap and the change in rate base. We begin with a fixed-effects version of the analysis. Our preferred version includes time fixed effects, λ_t, at the year-of-sample level and the unit fixed effects, θ_i, are at the service type, utility company and state level. Utilities that operate in multiple states still file rate cases with each state's utility regulator. Our state fixed effects account for constant differences across states, including any persistent differences in the regulator. Here, the identifying assumption is that after controlling for state and year effects, there are no omitted variables that would be correlated with both our estimate of the RoE gap and the utility's change in rate base. The identifying variation is the differences in the RoE gap within the range of rate case decisions for a given utility, relative to the annual average across all utilities.

The fixed effects handle some of the most critical threats to identification, such as macroeconomic trends, technology-driven shifts in electrical consumption, or static differences in state PUC behavior. Of course, potential threats to causal identification remain. One possibility is omitted variables – perhaps regulators in some states change their posture toward utilities over time, in a way that is correlated with both the RoE and the change in rate base. Another possibility is reverse causation – perhaps the regulator pushes for more capital investment (e.g. aiming to increase local employment) and the utility, facing increasing marginal costs of capital, needs a higher RoE.

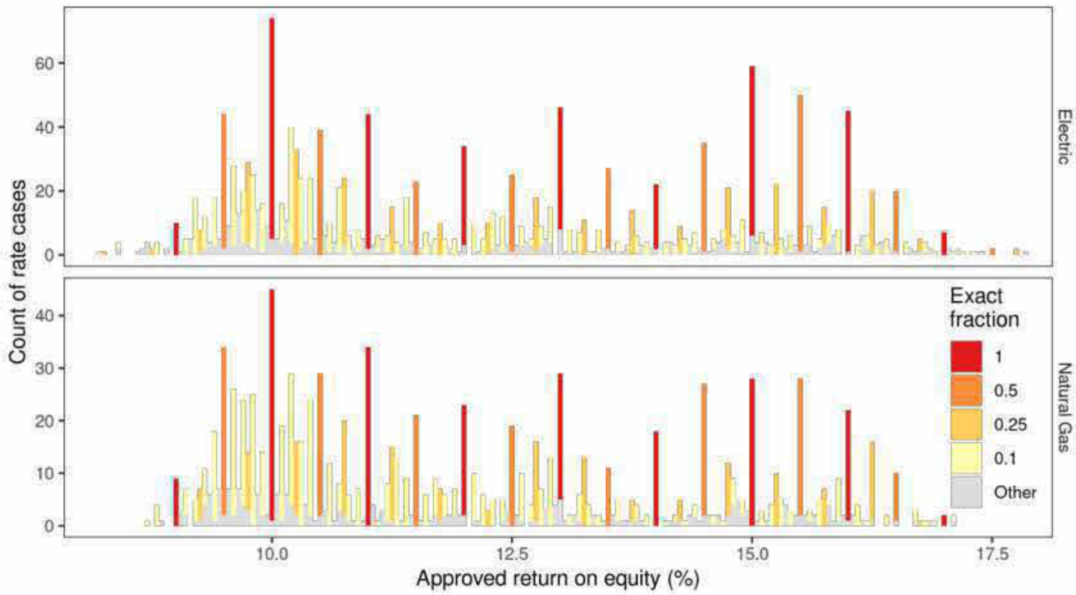
4.3.2 Instrumental Variables Specifications

To try and further deal with concerns regarding identification, we examine an instrumental variables approach based on the timing and duration of rate cases. The average utility has ten rate cases over the course of our sample period and the average rate case is in effect for about three years. Our IV analysis takes the idea that market measures of the cost of capital move around in ways that aren't always easy for the regulator to anticipate. For instance, if the allowed return on equity is set in year 0 and financial conditions change in year 2 such that the RoE gap increases, then we would expect the utility to increase their capital investments in ways that are unrelated to other aspects of the capital investment decision. For this instrument to work, it needs to be the case that these movements in capital markets are conditionally independent of decisions that the utility is making, except via this return on equity channel. We control for common year fixed effects, and then the variation that drives our estimate is that different utilities will come up for their rate case at different points in time.

A second IV strategy we explore is to exploit an apparent bias toward round numbers, where regulators tend to approve RoE values at integers, halves, quarters, and tenths of percentage points. Unfortunately this instrument does not produce a strong first-stage and so is not a core focus of our subsequent analysis. Even so, the existence of such an arbitrary phenomenon in our setting is still interesting, and can be seen clearly in figure 3. Small deviations created by rounding have large implications for utility revenues and customer payments. If for instance, a PUC rounds in a way that changes the allowed RoE by 10 basis points (0.1%), the allowed revenue on the existing rate base for the average electric utility in 2019 would change by $114 million (the median is lower, at $52 million).

We believe the actual, unknown, cost of equity is smoothly distributed. There is therefore some unobserved RoE* that is unrounded. The regulatory process often then rounds from RoE* to the nearest multiple of 10 or 25 basis points (bp). We argue that this introduces an exogenous source of variation into the actual approved RoE. To construct our instrument we calculate the difference between the observed RoE and the nearest rounded RoE. We take the absolute value of this difference and interact it with a dummy for the sign of the difference. When we say "rounded", we

Figure 3: Return on equity is often approved at round numbers



Colors highlight values of the nominal approved RoE that fall exactly on round numbers. More precisely, values in red are integers. Values in dark orange are integers plus 50 basis points (bp). Lighter orange are integers plus 25 or 75 bp. Yellow are integers plus one of {10, 20, 30, 40, 60, 70, 70, 80, 90} bp. All other values are gray. Histogram bin widths are 5 bp. Non-round values remain gray if they fall in the same histogram bin as a round value. In that case, the bars are stacked.

SOURCE: Regulatory Research Associates (2021).

don't know the rounding rule (e.g. up, down, or nearest) and it may differ across utilities and regulators. Our preferred specification uses numbers rounded up to 25 bp, but we check multiples of 10, 50 and 100 bp. For the instrument to be valid, we need to assume that the rounding is related to rate base only via assigned RoE. As noted earlier, because any rounding only accounts for a small portion of the variation in overall RoE, this instrument does not have a strong first stage.

5 Results

5.1 Return on Equity Gap Results

Beginning with the RoE gap analysis from section 4.1, we find there has been an increase in the gap between utilities' allowed return on equity and various measures of their estimated cost of capital. Our results on the RoE gap show this has increased

Table 2: RoE gap, by different benchmarks (percentage points)

A: Electric	Corp	UST	UST auto	CAPM low	CAPM high	UK
1985	0.693	0.415	1.39	1.50	−2.84	
1990	−0.238	0.459	0.412	1.36	−3.09	
1995	0.788	1.09	0.139	2.09	−2.49	
2000	0.666	1.41	0.153	2.42	−1.76	2.79
2005	2.99	2.84	0.722	3.91	−0.552	1.93
2010	3.04	3.21	0.517	4.50	−0.448	−0.585
2015	3.57	3.64	0.416	4.99	0.446	2.77
2020	4.25	4.49	0.706	5.60	0.786	1.88
B: Natural Gas						
1985	1.14	0.798	1.78	1.68	−2.35	
1990	−0.0272	0.848	0.819	1.59	−2.50	
1995	0.873	1.18	0.238	1.99	−2.27	
2000	0.757	1.35	0.0924	2.18	−1.65	
2005	2.85	2.70	0.623	3.54	−0.635	
2010	3.25	3.35	0.707	4.31	−0.516	
2015	3.98	4.01	0.850	5.04	0.646	2.43
2020	4.58	4.86	1.09	5.67	1.06	1.55

Note: Gap percentage figures are a weighted average across utilities, weighted by rate base. For cases where it's relevant the benchmark date is January 1995. See text for details of each benchmark calculation.

over time and are summarized in Table 2.

When benchmarking against changes in market measures of the cost of capital (e.g. 10-yr US Treasury bonds or Moody's corporate bonds) the RoE gap is around 4–4.5 percentage points. It seems plausible that such a large divergence should not arise over the long-term unless the utility sector were to undergo substantial changes.

It is not clear that the cost of equity should necessarily move in a one-for-one manner with these two measures of bond yields. Using the more conservative automatic update rule, which adjusts at half the rate of changes in bond yields, produces an RoE gap by 2020 of around 0.5–1 percentage points. Whether adjusting at 50% of the change in bond yields is the correct approach is unclear. For instance, Canada has used a 75% adjustment ratio in the past. What is clear is that even using this more conservative approach, we still see a divergence between allowed equity returns today and changes in the benchmark cost of capital.

Benchmarking against changes in bond yields relative to some baseline year is necessarily quite simplistic. Our two implementations of the CAPM approach allow us to see how a standard method used in the industry performs. Our "low" version of the CAPM uses assumptions for the risk-free rate, beta and market risk premium that are on the lower end of what has been historically used in the industry. This is particularly true when looking at the practices of US regulators, which appear to utilize higher values than regulators in the UK, Europe and Australia. The result is an RoE gap by 2020 of around 5.5 percentage points.[19] Looking back to the 1980s and 1990s though, the RoE gap becomes much smaller, with predictions of the cost of equity from our "low" CAPM version only showing a 2 percentage point gap against allowed rates of return.

Our "high" version of the CAPM uses assumptions for the risk-free rate, beta and

19. At this point average allowed RoE for US utilities is around 10%, compared with a CAPM prediction for the cost of equity of 4–5%.

market risk premium that are on the higher end of what has been historically used in the industry. This produces an RoE gap by 2020 of around 1 percentage points. Allowed rates of return are therefore still above the predictions from our "high" CAPM case, although much more closely aligned with the current approach of US state PUCs. Notably though, projecting this same approach back in time appears to suggest that past allowed returns in the 1980s and 1990s were well below the estimated cost of equity. This seems implausible given the large capital expenditures the industry has continued to engage in over the last four decades.

Lastly, when comparing against UK utilities we see a fairly consistent premium, with an RoE gap in 2020 of around 2 percentage points. A similar premium would likely emerge when comparing to utilities in other countries in Europe which have tended to approve similar rates of return to those we find for the UK. There are good reasons to think that US state PUCs should not simply adopt UK rates of return – there are many differences between the utility sector and investor environment in the US and UK. Even so, it is striking that other countries are able to attract sufficient investment in their gas and electric utilities while guaranteeing lower regulated returns than are available in the US context.

5.2 Asymmetric Adjustment Results

One mechanism for the emergence of the RoE gap is asymmetric adjustment of allowed return on equity to underlying benchmark rates of return. Table 3 provides the results of this analysis. Here we do find some potential evidence of asymmetric adjustment. Focusing on the US Treasury Bond benchmark and proposed returns on equity (column 1), the coefficient on the positive error correction term, θ^{+}, is -0.0111. This estimate indicates that where the actual return on equity is above the long-run equilibrium (e.g. due to a negative shock to the benchmark) there will be slow convergence back toward equilibrium at a rate of 1.11% of the difference

Table 3: Asymmetric Adjustments in Return on Equity

Model:	(1)	(2)	(3)	(4)
Variables				
θ+	-0.0111***	-0.0085***	-0.0120***	-0.0097***
	(0.0018)	(0.0022)	(0.0020)	(0.0020)
θ-	-0.0274***	-0.0320***	-0.0207***	-0.0229***
	(0.0075)	(0.0107)	(0.0057)	(0.0073)
Approved RoE			Yes	Yes
Index Baa Corp		Yes		Yes
Index UST 10yr	Yes		Yes	
Time Series				
LR coef.	0.5775	0.6054	0.5173	0.5411
θ+=θ- Fstat	4.132	3.631	2.146	2.504
θ+=θ- pval	0.0421	0.0567	0.1430	0.1136
Fit statistics				
Observations	116,537	116,537	94,012	94,012
R^2	0.02	0.01	0.01	0.01
Adjusted R^2	0.02	0.01	0.01	0.01

Clustered (Year) standard-errors in parentheses
Signif. Codes: ***: 0.01, **: 0.05, *: 0.1

NOTES: θ^+ is the coefficient on the positive error correction term (convergence when actual RoE is above long-run equilibrium). θ^- is the coefficient on the negative error correction term (convergence when actual RoE is below long-run equilibrium). "LR Coef" refers to the long-run β coefficient from the initial regression: $RoE_{i,t} = \beta Index_{i,t-1} + \varepsilon_{i,t}$.

each month. Conversely, the coefficient on the negative error correction term, θ^-, is -0.0274. This indicates that where the actual return on equity is below the long-run equilibrium there will be more rapid convergence back toward equilibrium at a rate of 2.74% of the difference each month. To put it more clearly, a sudden increase in the benchmark cost of capital will result in a faster subsequent rise in utilities' return on equity, while a sudden decrease in the benchmark cost of capital will result in a slower subsequent fall in utilities' return on equity.

Across all specifications we consistently see this pattern repeated whereby long-run adjustments occur faster for increases in the benchmark cost of capital than for decreases ($\theta^+ < \theta^-$). Notably though, this difference is more clearly statistically significant for proposed rates of return (columns 1–2) rather than for approved rates of return (columns 3–4). This is consistent with the rates that utilities propose being more likely to exhibit this kind of asymmetric behavior. The regulatory approval process may serve to dampen the asymmetry somewhat, although given the consistent differences in the magnitudes of the coefficients it does not appear to eliminate it entirely.

5.3 Rate Base Impact Results

We next consider how the RoE gap affects capital ownership in Table 4. Across our fixed effects specifications (columns 1–3) we find broadly consistent results. A 1 percentage point increase in the approved RoE gap leads to a 5.6–8.7% higher increase in approved rate base. Our IV specification using rate case timing (column 4) has a strong first stage (Kleibergen–Paap F-stat of 69). [20] Using this approach we find an effect of 5.3% which broadly aligns with our fixed effects estimates. This is our preferred specification.

In addition to looking at the increase in the rate base, we also look at the total

20. Our IV specification using rounding has a weak first stage (Kleibergen–Paap F-stat of 2.1) and so is not presented here.

Table 4: Relationship Between Approved Rate of Return and Approved Rate Base Increase

	Fixed effects specs.			IV
Model:	(1)	(2)	(3)	(4)
Variables				
RoE gap (%)	0.0551***	0.0752***	0.0867***	0.0523**
	(0.0200)	(0.0240)	(0.0225)	(0.0252)
Fixed-effects				
Service Type	Yes	Yes	Yes	Yes
State	Yes	Yes	Yes	Yes
Year		Yes	Yes	Yes
Company			Yes	Yes
Fit statistics				
Observations	2,491	2,491	2,491	2,491
R^2	0.33	0.36	0.69	0.69
Within R^2	0.01	0.004	0.01	0.009
Wald (1st stage), RoE gap (%)				69.1
Dep. var. mean	38.63	38.63	38.63	38.63

Clustered (Year & Company) standard-errors in parentheses
Signif. Codes: ***: 0.01, **: 0.05, *: 0.1

NOTES: The table uses approved RoE. The dependent variable is log of the utility's rate base increase in millions of $. Columns 1–3 show varying levels of fixed effects. Column 4 is the IV discussed in section 4.3. Our preferred specification is column 4 of table 4. First-stage *F*-statistic is Kleibergen–Paap robust Wald test.

Table 5: Relationship Between Approved Rate of Return and Approved Total Rate Base (both absolute and per MWh; electric utilities only)

Model:	Total, FE (1)	Total, IV (2)	per MWh, FE (3)	per MWh, IV (4)
Variables				
RoE gap (%)	0.0524***	0.0779**	0.1202**	0.1204
	(0.0188)	(0.0301)	(0.0571)	(0.0751)
Fixed-effects				
Service Type	Yes	Yes	Yes	Yes
State	Yes	Yes	Yes	Yes
Year	Yes	Yes	Yes	Yes
Company	Yes	Yes	Yes	Yes
Fit statistics				
Observations	1,787	1,787	705	705
R^2	0.85	0.85	0.84	0.84
Within R^2	0.006	0.004	0.02	0.02
Wald (1st stage), RoE gap (%)		25.6		21.2
Prop. or Appr.	Appr.	Appr.	Appr.	Appr.
Dep. var. mean	1,516.5	1,516.5	379.5	379.5

Clustered (Year & Company) standard-errors in parentheses
Signif. Codes: ***: 0.01, **: 0.05, *: 0.1

NOTES: The table uses approved RoE. Dependent variables are the total rate base in millions of $ (Columns 1–2) and the rate base per quantity delivered in $ per MWh (Columns 3–4). The FE results correspond to the specification used for column 3 in table 4 and the IV results correspond to the specification used for column 4 in table 4. First-stage *F*-statistic is Kleibergen–Paap robust Wald test.

rate base and the total rate base per MWh. These results are in Table 5. We find similar effects for the total rate base, and the effects for total rate base per MWh are potentially even larger. However, these findings are less precisely estimated, in part due to data quality challenges. [21] Overall we take these results as providing evidence that higher equity returns do lead utilities to increase their capital holdings. [22]

As a caveat, we note that an utility can increase their capital holdings in two

21. The total rate base data is less complete. Also when calculating on a per MWh basis, we are only able to merge quantity data for a subset of years for electric utilities.

22. The equivalent results from looking at the proposed changes to the rate base can be found in the appendix.

distinct ways. One option is to reshuffle capital ownership, either between subsidiaries or across firms, so that the utility ends up with more capital on its books, but the total amount of capital is unchanged. The second option is to actually buy and own more capital, increasing the total amount of capital that exists in the state's utility sector. We do not differentiate between these two cases. Because we don't differentiate, we consider excess payments by utility customers, but we remain agnostic about the socially optimal level of capital investment.

5.4 Excess Consumer Cost Results

Table 6: Excess costs, by different benchmarks (2019$ billion per year)

A: Electric		Corp	UST	UST auto	CAPM low	CAPM high	UK
Fixed	2000	1.03	2.37	0.250	4.21	−2.74	4.71
	2020	8.58	9.40	1.43	11.8	1.83	3.90
Adjust	2000	1.06	2.55	0.252	4.76	−2.48	5.42
	2020	10.5	11.7	1.49	15.4	1.91	4.29
B: Natural Gas							
Fixed	2000	0.165	0.371	0.0226	0.620	−0.415	
	2020	2.44	2.76	0.624	3.24	0.655	0.886
Adjust	2000	0.171	0.398	0.0227	0.693	−0.378	
	2020	3.05	3.48	0.661	4.23	0.692	0.959

Note: Excess payments are totals for all IOUs in the US, in billions of 2019 dollars per year. Missing rate base data for utilities in our sample was interpolated based on the estimated average growth rate of the rate base over time. The "fixed" rows take the observed rate base as fixed and estimates excess payments. The "adjust" rows also account for changes in the rate base size, as estimated in table 4 column 4. For cases where it's relevant the benchmark date is January 1995. See text for details of each benchmark calculation.

Table 6 summarizes our estimates of the excess cost for utility customers. Here we multiply the rate base by the RoE gap to come up with a measure of the additional payments made to cover the premium in equity returns. To ensure these excess costs are calculated for all utilities in our sample, we must remedy the missing rate base data for some utilities, particularly in the earlier years of our sample. [23] To do this we interpolate using an estimate of the average growth rate for the rate base over time. [24]

Across our five benchmark measures and using the existing rate base we find excess costs to consumers in 2020 of $2–15 billion per year. These excess costs, like the RoE gap, depend on the choice of baseline. The economic welfare loss is likely smaller than these excess cost measures – the excess capital provides non-zero benefit, and the ultimate recipients of utility revenues place some value on the additional income.[25]

Accounting for the way the RoE gap can affect capital ownership increases our estimate of the excess cost to consumers to $2–20 billion per year. The majority of these costs come from the electricity sector.[26]

6 Conclusion

Utilities invest a great deal in capital, and need to be compensated for the opportunity cost of their investments. Getting this rate of return correct, particularly the return on equity, is challenging, but is a first-order important task for utility regulators.

Our analysis shows that the RoE that utilities are allowed to earn has changed

23. Approved rate base data is available for 95% of utilities in 2020 and 65% of utilities in 2000.

24. We regress approved rate base on time, controlling for utility by state by service type fixed effects. Within each grouping of utility, state and service type, we start with the first non-missing value and linearly interpolate backwards assuming the rate base changes from period to period according to our estimated growth rate.

25. The RoE gap will ultimately affect utility rates, including the costs of buying electricity, but the ultimate impact on consumption decisions will depend on each utility's rate structure. Analyzing these is outside the scope of this paper.

26. For comparison, total 2019 electricity sales by investor owned utilities were $204 billion, on 1.89 PWh of electricity (US Energy Information Administration 2020a). Natural gas sales to consumers are $146 billion on 28.3 trillion cubic feet of gas US Energy Information Administration 2020b. These figures include sales to residential, commercial, industrial, and electric power, but not vehicle fuel. They also include all sales, not just those by investor owned utilities.

dramatically relative to various financial benchmarks in the economy. We estimate that the current approved average return on equity is substantially higher than various benchmarks and historical relationships would suggest. These results are necessarily uncertain, and depending on our chosen benchmark for the cost of equity the premium ranges from 0.5–5.5 percentage points. Put another way, even our most conservative benchmarks come in below the allowed rates of return on equity that regulators set today.

We link this divergence to the apparent asymmetric adjustment of rates to changes in market measures of the cost of capital. Increases to benchmark measures of the cost of capital lead to faster rises in utility returns on equity than is the case for decreases. This is the so-called "rockets and feathers" phenomenon and could be indicative of regulators being more responsive to pressures from the utilities they regulate than from consumers' demands to keep prices down.

We then turned to the Averch–Johnson effect, and estimated the additional capital this RoE gap generates. In our preferred specification, we estimate that an additional percentage point in the RoE gap leads to 5% higher rate base increases. Depending on our chosen benchmark for the gap, the excess rates collected from consumers could amount to $2–20 billion per year.

If utilities are earning excess equity returns, a key challenge is to identify what changes to the ratemaking process may help remedy this. Regulators have taken numerous steps over the past few decades to improve the way costs are passed through into rates. For instance, explicit benchmarking and automatic update rules were introduced for fuel costs decades ago. It seems plausible that they could also be used to help equity costs adjust more quickly to changing market conditions, and do so in ways that are less prone to the subjective negotiations of the ratemaking process.

However, the cost of equity is unlikely to perfectly track any single benchmark in the same way as the cost of fuel. Also the automatic update rules for equity returns that have already been put in place by some PUCs have done little to prevent the trends we highlight.[27] As such, a significant degree of regulatory judgment is inevitable in this area.

A clear first step for improving the decisions regulators make over the cost of equity is to avoid some of the arbitrary "rules of thumb" that have been employed to date – see for instance the evidence we find of whole number rounding, or the reluctance to set rates below a nominal 10% that Rode and Fischbeck (2019) highlight.

Bolstering the financial expertise of regulators is another promising path forward.[28] Seemingly objective methods like the capital asset pricing model cannot provide a definitive answer on the cost of equity. As we have documented, a range of plausible input assumptions can lead to widely divergent estimates of the cost of equity. When incorporating evidence from these methods regulators need to have the expertise to understand their limitations and push back on the assumptions utilities put forward when using them.

Lastly, process reforms may also be beneficial. In most rate case proceedings, utilities submit their planned expenditures and then regulators decide whether they are prudent. This relies on the notion that utilities are best placed to forecast their detailed needs for labor, materials and equipment (e.g. numbers of new transformers needed and where). However, it is less clear that utilities possess the same unique level of insight when it comes to the cost of equity, especially given that this is so dependent on wider market forces, the performance of peer companies and general investor sentiment. For this component of utility costs the regulator could conduct its own independent internal analysis of the cost of equity first, and then consult on their proposals. In this way it is the regulator that is anchoring the starting point of

27. For instance, regulators at the California PUC feel that the rule, called the cost of capital mechanism (CCM), performed poorly. "The backward looking characteristic of CCM might have contributed to failure of ROEs in California to adjust to changes in financial environment after the financial crisis. The stickiness of ROE in California during this period, in the face of declining trend in nationwide average, calls for reassessment of CCM." (Ghadessi and Zafar 2017)

28. Azgad-Tromer and Talley (2017) found that providing finance training to regulatory staff did have a moderate effect on moving rates of return closer to standard asset pricing predictions.

the discussion, not the utility.

Our findings have important implications beyond just the additional cost they place on consumers. From a distributional standpoint, higher rates create a transfer from ratepayers to utility stockholders. A high rate of return for *regulated* utilities may also lead to a reshuffling of which assets are owned by regulated versus non-regulated firms. Finally, efficiently pricing energy has important implications for environmental policy, particularly with regard to encouraging electrification which is a key component of efforts to tackle climate change.

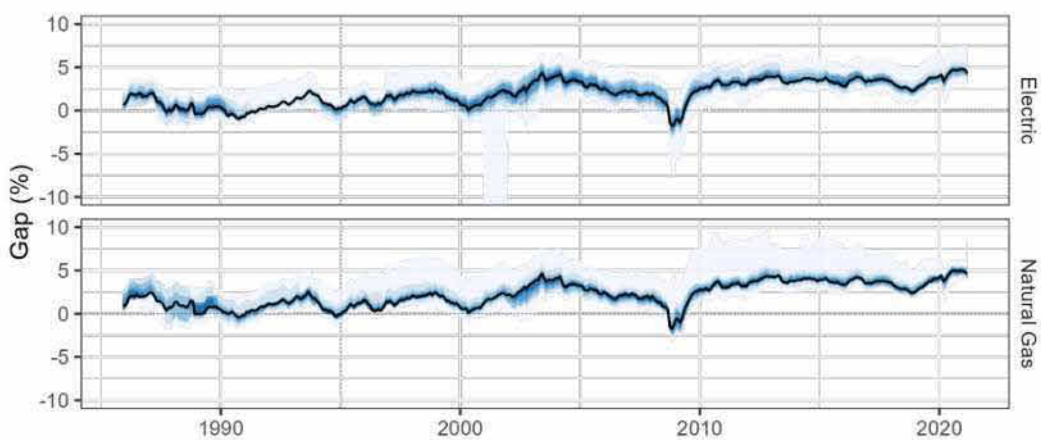
Appendix

A Detail on RoE gap benchmarks

For each of the strategies we utilize, we plot the timeseries of the RoE gap. These are plotted in figures 4, 5, 6, 7, 8, and 9.

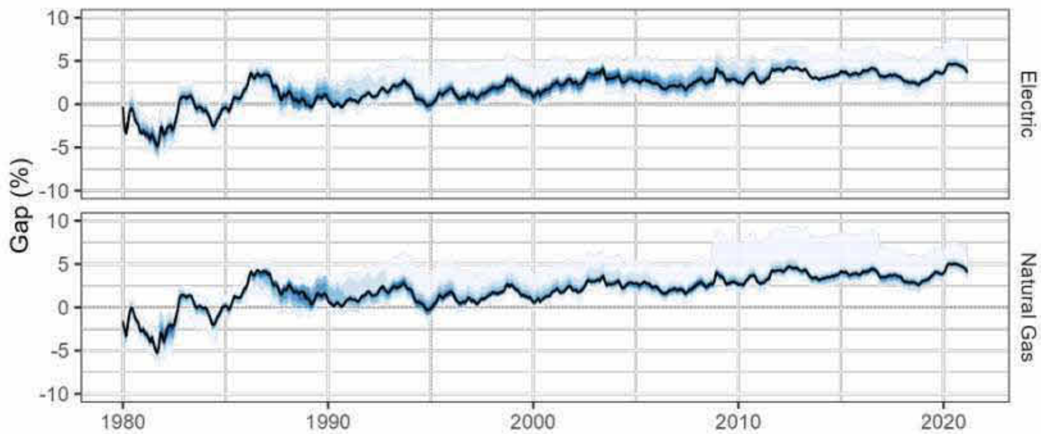
In each plot, we present the median of our RoE gap estimates, weighting by the utility's rate base (in 2019 dollars). Our goal is to show the median of rate base dollar value, rather than the median of utility companies, as the former is more relevant for understanding the impact of the RoE gap. We also show bands, in different shades of blue, that cover the 40–60 percentile, 30–70 percentile, 20–80 percentile, 10–90 percentile, and 2.5–97.5 percentile (all weighted by rate base).

Figure 4: Return on equity gap, benchmarking to same-rated corporate bonds



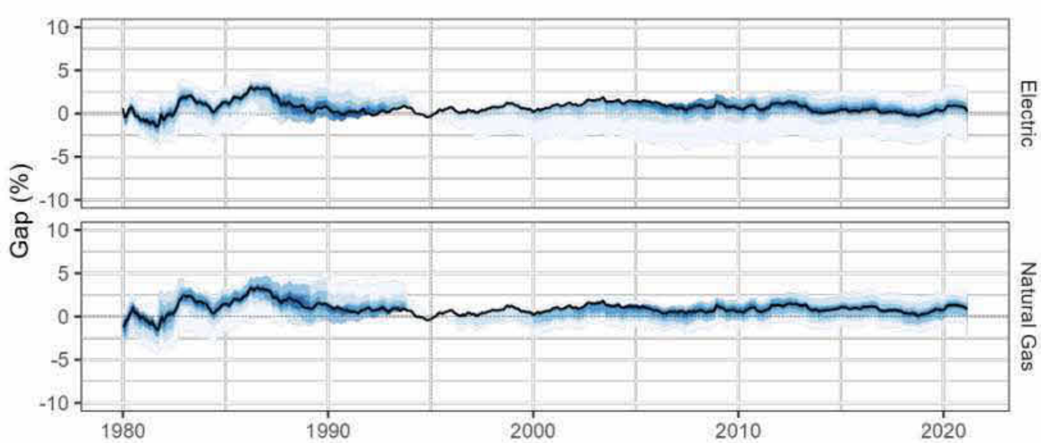
Base year is 1995. Line represents median; shading represents ranges that cover the central 20, 40, 60, 80, and 95% of total IOU rate base. See calculation details in section 4.1.

Figure 5: Return on equity gap, benchmarking to 10-year Treasuries



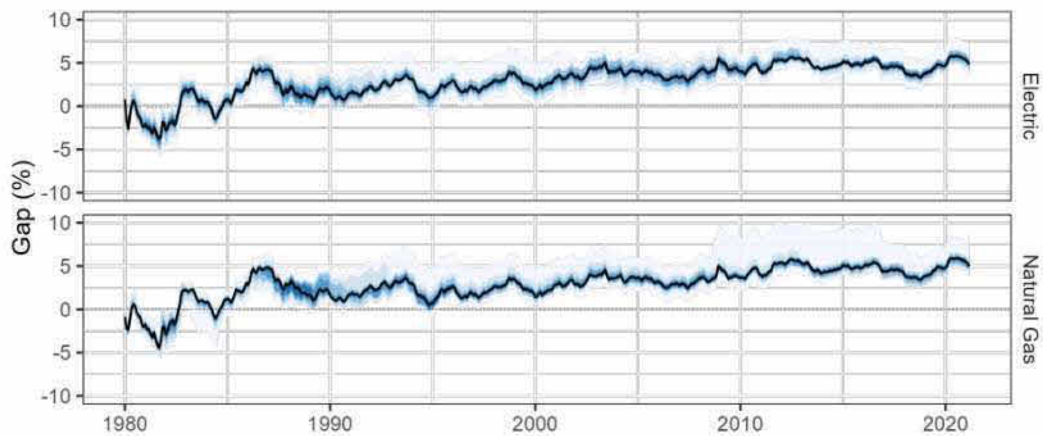
Line represents median; shading represents ranges that cover the central 20, 40, 60, 80, and 95% of total IOU rate base. See calculation details in section 4.1.

Figure 6: Return on equity gap, using automatic update rule



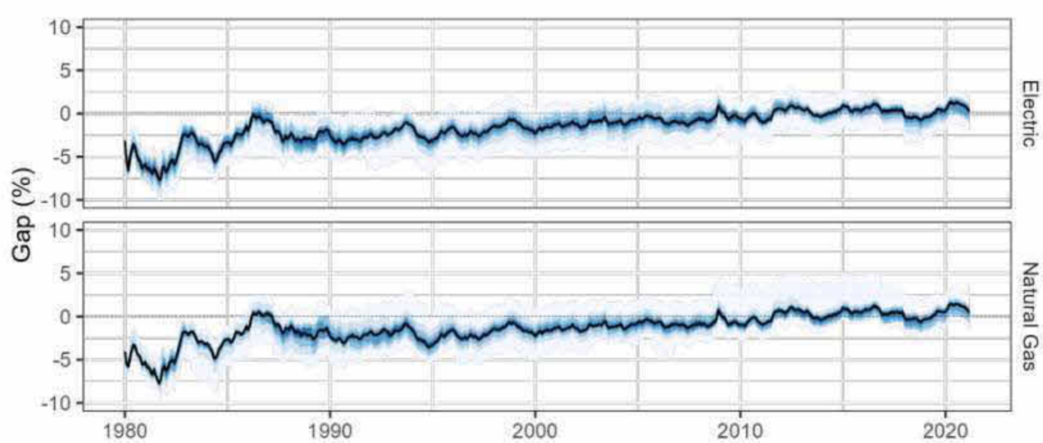
Line represents median; shading represents ranges that cover the central 20, 40, 60, 80, and 95% of total IOU rate base. See calculation details in section 4.1.

Figure 7: Return on equity gap, benchmarking to CAPM (low)



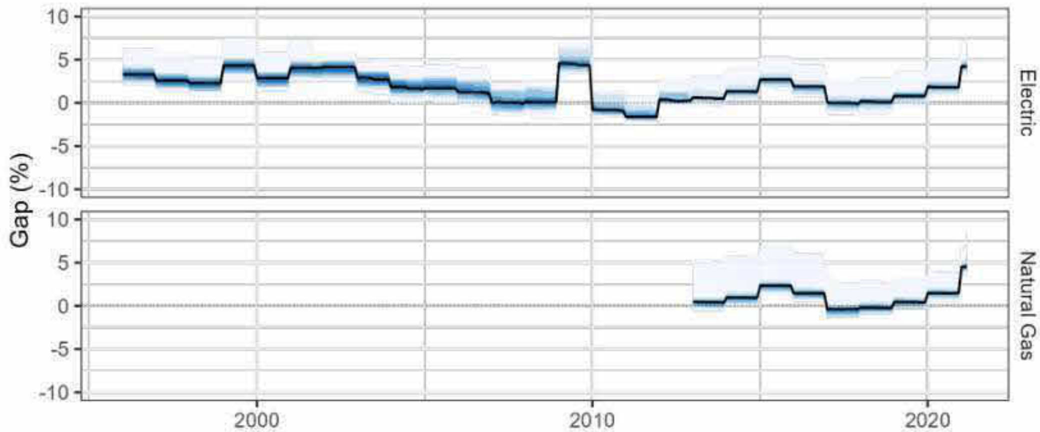
Line represents median; shading represents ranges that cover the central 20, 40, 60, 80, and 95% of total IOU rate base. See calculation details in section 4.1.

Figure 8: Return on equity gap, benchmarking to CAPM (high)



Line represents median; shading represents ranges that cover the central 20, 40, 60, 80, and 95% of total IOU rate base. See calculation details in section 4.1.

Figure 9: Return on equity gap, compared to UK utilities



Line represents median; shading represents ranges that cover the central 20, 40, 60, 80, and 95% of total IOU rate base. See calculation details in section 4.1.

B Detail on Rate Base Impacts

Here we include additional information on our analysis of rate base impacts. The results include estimates using proposed (instead of approved) rate base changes, as well as estimates using the total rate base.

Table 7: Relationship Between Proposed Rate of Return and Proposed Rate Base Increase

	Fixed effects specs.			IV
Model:	(1)	(2)	(3)	(4)
Variables				
RoE gap (%)	0.0670***	0.0436*	0.0672***	0.0353
	(0.0134)	(0.0217)	(0.0151)	(0.0215)
Fixed-effects				
Service Type	Yes	Yes	Yes	Yes
State	Yes	Yes	Yes	Yes
Year		Yes	Yes	Yes
Company			Yes	Yes
Fit statistics				
Observations	3,210	3,210	3,210	3,210
R^2	0.37	0.39	0.73	0.73
Within R^2	0.02	0.002	0.01	0.008
Wald (1st stage), RoE gap (%)				50.9
Dep. var. mean	63.69	63.69	63.69	63.69

Clustered (Year & Company) standard-errors in parentheses
*Signif. Codes: ***: 0.01, **: 0.05, *: 0.1*

NOTES: The table uses proposed RoE. The dependent variable is log of the utility's rate base increase in millions of $ Columns 1–3 show varying levels of fixed effects. Column 4 is the IV discussed in section 4.3. First-stage *F*-statistic is Kleibergen–Paap robust Wald test.

Table 8: Relationship Between Proposed Rate of Return and Proposed Total Rate Base (both absolute and per MWh)

Model:	Total, FE (1)	Total, IV (2)	per MWh, FE (3)	per MWh, IV (4)
Variables				
RoE gap (%)	0.0384	0.0704**	0.1490**	0.1610**
	(0.0232)	(0.0348)	(0.0702)	(0.0720)
Fixed-effects				
Service Type	Yes	Yes	Yes	Yes
State	Yes	Yes	Yes	Yes
Year	Yes	Yes	Yes	Yes
Company	Yes	Yes	Yes	Yes
Fit statistics				
Observations	2,140	2,140	919	919
R^2	0.83	0.83	0.83	0.83
Within R^2	0.003	0.0008	0.03	0.03
Wald (1st stage), RoE gap (%)		19.7		15.1
Prop. or Appr.	Prop.	Prop.	Prop.	Prop.
Dep. var. mean	1,583.5	1,583.5	404.4	404.4

Clustered (Year & Company) standard-errors in parentheses
Signif. Codes: ***: 0.01, **: 0.05, *: 0.1

NOTES: The table uses proposed RoE. Dependent variables are the total rate base in millions of \$ (Columns 1–2) and the rate base per quantity delivered in \$ per MWh (Columns 3–4). The FE results correspond to the specification used for column 3 in table 4 and the IV results correspond to the specification used for column 4 in table 4. First-stage *F*-statistic is Kleibergen–Paap robust Wald test.

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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JIM O'CONNOR – CHAIR
LEA MÁRQUEZ PETERSON
ANNA TOVAR
KEVIN THOMPSON
NICK MYERS

IN THE MATTER OF THE APPLICATION OF	)	
TUCSON ELECTRIC POWER COMPANY FOR	)	
THE ESTABLISHMENT OF JUST AND	)	
REASONABLE RATES AND CHARGES	)	
DESIGNED TO REALIZE A REASONABLE	)	DOCKET NO. E-01933A-22-0107
RATE OF RETURN ON THE FAIR VALUE OF	)	
THE PROPERTIES OF TUCSON ELECTRIC	)	
POWER COMPANY DEVOTED TO ITS	)	
OPERATIONS THROUGHOUT THE STATE OF	)	
ARIZONA AND FOR RELATED APPROVALS	)	

SURREBUTTAL TESTIMONY OF

KEVIN M. LUCAS

ON BEHALF OF

ARIZONA SOLAR ENERGY INDUSTRIES ASSOCIATION ("ARISEIA")

AND SOLAR ENERGY INDUSTRIES ASSOCIATION ("SEIA")

ON RATE DESIGN

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I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE FOR THE RECORD YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A1. My name is Kevin Lucas. I am the Senior Director of Utility Regulation and Policy at the Solar Energy Industries Association ("SEIA"). My business address is 1425 K St. NW #1000, Washington, DC 20005.

Q2. ARE YOU THE SAME KEVIN LUCAS THAT FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A2. Yes, I am.

Q3. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A3. My testimony is provided on behalf of Intervenors, SEIA and AriSEIA.

Q4. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A4. My testimony addresses several Tucson Electric Power Company ("TEP" or "the Company") witnesses' rebuttal testimony. Specifically, I address the following TEP witnesses and issues:

- Dallas Dukes,[1] regarding the Company's failure to respond to my testimony on a Bring Your Own Device ("BYOD") program, and on residential and commercial tariffs designed to support behind-the-meter ("BTM") storage.
- Jared. C. Dang, regarding the Company's discussion of the DG Meter Fee.[2]
- Richard D. Bachmeier, regarding the Company's TOU rate design and its analysis of demand rate bill impacts.[3]

Q5. WHAT ARE YOUR CONCLUSIONS?

A5. The Company's complete failure to address my testimony regarding BYOD and BTM storage tariffs is unacceptable. TEP claims these issues are "not central" to the rate case and, therefore, should be remanded to "separate proceedings outside this rate case" for review by stakeholders.[4] Unfortunately, given TEP's history of delay in similar proceedings, this path forward may result in the continued failure of even a single customer taking service on tariffs designed to support BTM storage. The Commission should mandate that TEP redo its tariffs

[1] Rebuttal Testimony of Dallas Dukes on Behalf of Tucson Electric Power Company. ("Dukes Rebuttal")
[2] Rebuttal Testimony of Jared C. Dang on Behalf of Tucson Electric Power Company. ("Dang Rebuttal")
[3] Rebuttal Testimony of Richard D. Bachmeier on Behalf of Tucson Electric Power Company. ("Bachmeier Rebuttal")
[4] Dukes Rebuttal at 16.

and establish a BYOD program that follows my recommendations within a specific, short time frame to prevent further delay from TEP.

The Company has been inappropriately collected Distributed Generation ("DG") Meter Fees for more than four years. While we appreciate the Company's admission that "there is no longer a basis for the fee" and that it will be discontinued going forward,[5] the Commission should require TEP to refund customers for the more than $1.5 million in fees over-collected since its advanced metering infrastructure ("AMI") rollout was approved in January 2019. The analysis that supported the original fee was obsolete nearly as soon as it was implemented, but at no point in the past four and a half years did TEP ever address the Commission regarding the change of circumstances. Absent diligence from AriSEIA and SEIA, this issue would likely have remained unaddressed, and the Commission should send a strong signal to TEP that over-collecting fees based on outdated information, as well as its failure to be forthcoming about that over-collection, is neither tenable nor tolerable.

The Company's current Time of Use ("TOU") rates are not robust, and even with its proposed changes, would remain weak. TEP discounted intervenor testimony recommending an increase in the peak to off-peak ratio in part by claiming these changes would negatively impact "risk associated with margin revenue collection and [] revenue stability."[6] While these are considerations for the Commission, they must be balanced against several other factors such as effectiveness of the rate design and evaluated within the scale of TOU revenue collections. I continue to recommend that the Commission order new TOU rates that have a steeper peak to off-peak differential to drive well-established demand savings.

TEP's demand-based rate analysis demonstrate the effectiveness of reducing bills for high load factor customers, but it fails in its claim that high load factor customers produce system cost savings or that its demand-based rates send appropriate signals to reduce on-peak usage. I utilized historic billing data to demonstrate that load factor was by far the most

[5] Dang Rebuttal at 7.
[6] Bachmeier Rebuttal at 18.

dominant determinant of bill savings on demand rates, even to the exclusion of on peak usage. Further, it is trivial to construct an example where a customer can increase their on-peak usage while still attaining a lower bill on the demand-based rate. Considering most months the Company's system has ample capacity to spare, individual customer's peak demand readings are not cost-reflective and the Company's demand-based rates should be discontinued for new customers.

II. REBUTTAL TO DALLAS DUKES ON RATE DESIGN

Q6. PLEASE SUMMARIZE THE TESTIMONY THAT YOU PROVIDED RELEVANT TO MR. DUKES REBUTTAL ON RATE DESIGN.

A6. I advocated for the creation of a performance-based BYOD program that would pay customers for discharging their BTM storage in response to Company-called events. These calls would occur up to 30 times per year in the summer for up to 3 hours each. Customers would be paid $150/kW based on their average discharge rate over the called events. This program is necessary to align incentives for BTM storage owners to utilize their batteries in a way that maximizes benefits to the broader grid.[7]

I also argued for a ground-up redesign of the residential R-TECH and commercial LGST-SP rates, which, while ostensibly designed to support BTM storage, have not attracted a single customer since their creation more than two years ago. I proposed removing unnecessary demand-based components from the R-TECH rate while recovering more revenue through energy-based rates on the LGST-SP tariff.[8]

Q7. WHAT WAS MR. DUKES' REBUTTAL TO YOUR TESTIMONY?

A7. Mr. Dukes entirely sidestepped my testimony, claiming "a rate case is not the forum for full and open discussion of narrow topics not central to the rate case itself."[9] He instead suggested

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[7] Lucas Direct at 311.
[8] Lucas Direct at 348.
[9] Dukes Rebuttal at 15.

that the Commission "create separate proceedings outside of this rate case to provide careful review" of these proposals.[10]

Q8. WHAT IS YOUR RESPONSE TO THIS TESTIMONY?

A8. It is extremely frustrating that TEP did not engage on this topic and continues to delay the development of programs and rates that can support BTM storage. Mr. Dukes' assertion that my testimony on these matters was "a narrow topic not central to the rate case itself" is befuddling. Rate design is a core issue in utility regulation, and rate cases are absolutely the correct forum for discussing and debating these issues. In fact, TEP itself sponsored testimony in its 2019 Rate Case related to the Economic Development Rate ("EDR").[11]

In that case, the Company stated "TEP's EDR was approved by the Commission in Phase I of the Company's previous rate case and has been effective since February 2017. However, because the EDR has been effective since the Company's last rate case and no customers are currently subscribed, the Company believes that some changes to eligibility requirements are necessary."[12] Mr. Bachmeier went on to discuss several changes that the Company believed would enhance the viability of the tariff.[13] The direct parallel to my testimony on the R-TECH and LGST-SP tariff could not be more obvious.

Mr. Bachmeier also offered testimony supporting the expansion of the GoSolar Shared program to large commercial customers,[14] and introduced the Company's proposed Market-Pricing Experimental Rate ("MP-EX"). The latter was originated by the Commission itself, which saw fit to have TEP propose such a rate in its next rate case.[15] Despite Mr. Dukes' protestations, rate design and programmatic implementations are neither "a narrow topic" nor considered by the Commission to be "not central to the rate case itself."

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[10] *Id*. at 16.
[11] Direct Testimony of Richard D. Bachmeier on Behalf of Tucson Electric Power Company at 17, Docket No. E-0933A-19-0028, April 1,2019.
[12] *Id.*
[13] *Id.* at 17-18.
[14] *Id.* at 18-19.
[15] *Id.* at 19.

Q9. WHILE TEP CHOSE NOT TO CONTRIBUTE TO THE RECORD ON THIS ISSUE, HAS THE COMMISSION WEIGHED IN ON SIMILAR TARIFF CHANGES IN PAST RATE CASES?

A9. Yes. The Commission approved several modifications to Arizona Public Service ("APS") R-TECH and E-32L-SP tariff (APS's version of TEP's LGST-SP tariff) in response to testimony from AriSEIA/SEIA.[16] While the Commission did not adopt all of our recommendations for these rates in that case, it required R-TECH revisions that we advocated for including the elimination of the off-peak demand charge and introduction to a lower, overnight TOU period.[17] Similarly, it adopted many of our recommendations for the E-32L-SP tariff, including removing the 20% demand reduction, reducing the duration of the on-peak period, creating a consistent differential between on-peak and remaining-hours demand rates, eliminating off-peak demand charges, and setting the basic service charge at the same level as the general E-32L rate.[18]

The Commission's order also stood up a collaborative stakeholder process that would continue to evaluate and recommend changes to the E-32L-SP rate and report back to the Commission.[19] These stakeholder meetings have been instructive, and led to an additional recommendation in my direct testimony to limit on-peak hours to weekdays.[20] Given that APS's original E-32L-SP rate and TEP's LGST-SP rates were structurally nearly identical – and both attracted zero customers – it is obvious that more stakeholder meetings are not needed to investigate what changes should be made. The Commission has already adopted many of our prior recommendations on this tariff, and we urge the Commission to implement our current recommendations for the TEP LGST-SP and avoid further delay.

Likewise, the Commission has considered testimony and required changes to the R-TECH tariff as implemented by APS. Our recommendations in this case largely mirror our recommendations in that case, and we urge the Commission to consider fully adopting our

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[16] Decision No. 78317 at 350, 376-377, Docket No. E-01345A-19-0236.
[17] *Id.* at 350
[18] *Id.* at 376-377.
[19] *Id.* at 377.
[20] Lucas Direct at 361.

recommendations in the TEP docket as a way to more fully engage customers who wish to install multiple advanced technologies. There is no reason to delay the process given the precedent that has already been established.

Q10. DO YOU HAVE SIMILAR CONCERNS REGARDING TEP'S PROPOSAL FOR THE BYOD PROGRAM?

A10. Yes. TEP's Customer Energy Storage Program ("CESP") was approved by the Commission on September 1, 2021.[21] However, the Company does not intend to "prepare the battery element" of this program until at least October 2023.[22] Given this timeline, requiring a new docket, new interventions, and new stakeholder processes will delay the program even further and add considerable cost and capacity constraints on the Commission and stakeholders. Each of those steps take resources and funding, and while TEP is in the enviable position to recover docket expenses from its captive customers, nonprofit intervenors such as SEIA and AriSEIA have no such recourse and must raise funds to participate in additional proceedings.

Given the context of Arizona's Resource Comparison Proxy ("RCP") export rate structure, the benefits of and need for the BYOD program were clearly and thoroughly laid out in my direct testimony.[23] TEP did not and should not have ignored this issue; doing so is a disservice to all parties. AriSEIA/SEIA's proposal is based on a successful program that has been implemented for years in the northeast, and we believe the Commission should approve the program in this docket with as many defined characteristics as possible. We request that the Commission approve of the core structure of the program and the establishment of a limited timeframe to finalize programmatic details.

Q11. HAVE YOU RECEIVED ADDITIONAL INFORMATION TO SUPPORT YOUR PROPOSED $150/KW CREDIT PAYMENT?

A11. Yes. TEP supplemented a data response after my direct testimony was filed to include the projected cost of large-scale storage. While customer owned BTM storage and large-scale storage are not identical products, the cost information is instructive. TEP's projected 2024

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[21] Lucas Direct at 340.
[22] *Id.*
[23] See e.g., Lucas Direct Section II.

levelized cost for a four-hour battery is \$202.12/kW-year, which falls slightly to \$183.41/kW-year in 2028.[24]

BTM storage has several attributes which are not shared by large-scale, centralized storage. First, BTM storage avoids line losses on the transmission and distribution system, which during peak hours can be significant. Further, BTM storage can help mitigate peak loads that risk overloading local distribution assets, but which may not trigger system-wide operational concerns. This has value by avoiding or deferring distribution upgrades and can be significant in certain circumstances where upgrades are expensive. BTM storage can also help support Volt/VAR functions on the distribution grid, enabling more distributed generation to connect without causing power quality issues. In light of these additional but currently unquantified values, setting the credit rate for our proposed BYOD program at \$150/kW is very reasonable.

Q12. WHAT DO YOU RECOMMEND REGARDING THE RATE DESIGN AND BYOD PROGRAM?

A12. I recommend the Commission approve the new rate designs and BYOD program as proposed in my direct testimony.

III. <u>REBUTTAL TO JARED. C. DANG REGARDING THE DG INCREMENTAL METER FEE</u>

Q13. PLEASE SUMMARIZE THE TESTIMONY THAT YOU PROVIDED RELEVANT TO MR. DANG'S REBUTTAL ON THE DG INCREMENTAL METER FEE.

A13. I analyzed the Company's DG Incremental Meter Fee ("Fee"), a monthly fee of \$2.23 and \$0.90 for residential and small commercial DG customers, respectively, assessed on DG customers. In my direct testimony, I demonstrated through extensive – although at the time, incomplete – discovery responses that TEP's Fee was based on outdated data that no longer reflects the types of meters the Company installs.[25] Further, I showed that the original calculation contained errors that inflated the cost of the fee.[26] Finally, I opined that the

[24] Exhibit KL-20, AriSEIA 3.4 Supplemental.
[25] Lucas Direct at 371.
[26] Lucas Direct at 375.

Commission should consider requiring TEP to issue a refund of these costs based on the timing of the Commission's order on the matter and the deployment of the Company's advanced metering infrastructure ("AMI") program.[27]

Q14. WHAT WAS TEP'S RESPONSE TO YOUR TESTIMONY?

A14. TEP fully admitted and agreed with my testimony regarding the lack of incremental cost associated with the Fee:

> The fee was originally based upon information that showed a significant cost difference between a cheaper AMR meter installation applicable to billing non-DG customers and the more expensive AMR bidirectional meter installation that was necessary for billing DG customers. However, over time the Company has moved towards utilizing the same bidirectional AMI meter for DG and non-DG customers, therefore there is no longer a basis for the fee. Accordingly, the Company will eliminate the DG Incremental Meter Fee on a going forward basis.[28]

Q15. DID THE COMPANY AGREE WITH YOUR RECOMMENDATION TO CREDIT BACK THE COSTS COLLECTED THROUGH THIS FEE?

A15. It did not. The Company stated "The DG Incremental Meter Fee was created in a Commission decision. Like other service fees that change or are eventually discontinued, this change should be made on a going forward basis upon Commission approval."[29]

Q16. SINCE FILING YOUR DIRECT TESTIMONY, HAVE YOU RECEIVED ADDITIONAL INFORMATION REGARDING THE FEE THAT BOLSTERS YOUR ARGUMENT REGARDING A REFUND?

A16. Yes. At the time I filed my direct testimony, there were still several open discovery questions regarding the Fee and the methodology behind the Company's cost calculation. As such, I was not certain that the incremental cost calculation was $0 given uncertainty around when the Company knew it was switching to bidirectional AMI meters for all customers.

Responses to these discovery questions were subsequently provided by the Company and clearly support my position that the Company knew or ought to have known at the time the fee was approved that it would soon be rendered obsolete. Further, the Company's

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[27] Lucas Direct at 378.
[28] Dang Rebuttal at 7.
[29] Dang Rebuttal at 8 (internal citations omitted).

statement above that "over time" it moved towards utilizing the same meters for DG and non-DG customers – and thus eliminating the incremental element of the fee – strains the meaning of those words. The reality is that fewer than four months passed between when the Fee was approved and when the Company knew beyond a shadow of a doubt that Fee should be eliminated.

Q17. HOW MANY CUSTOMERS ARE CURRENTLY BEING CHARGED A FEE?

A17. As of December 2022, the Company was levying this fee on 25,236 customers.[30]

Q18. HOW MUCH HAS THE COMPANY COLLECTED THROUGH THE FEE?

A18. In its first full month of operation in October 2018, the Fee was applied to about 5,200 customers and collected $11,586 in revenue. This has steadily increased over time as seen in Figure 1, with December 2022 resulting in revenue collections of $56,615 from 25,558 customers.[31] In total, the Company has collected $1.56 million through this fee.

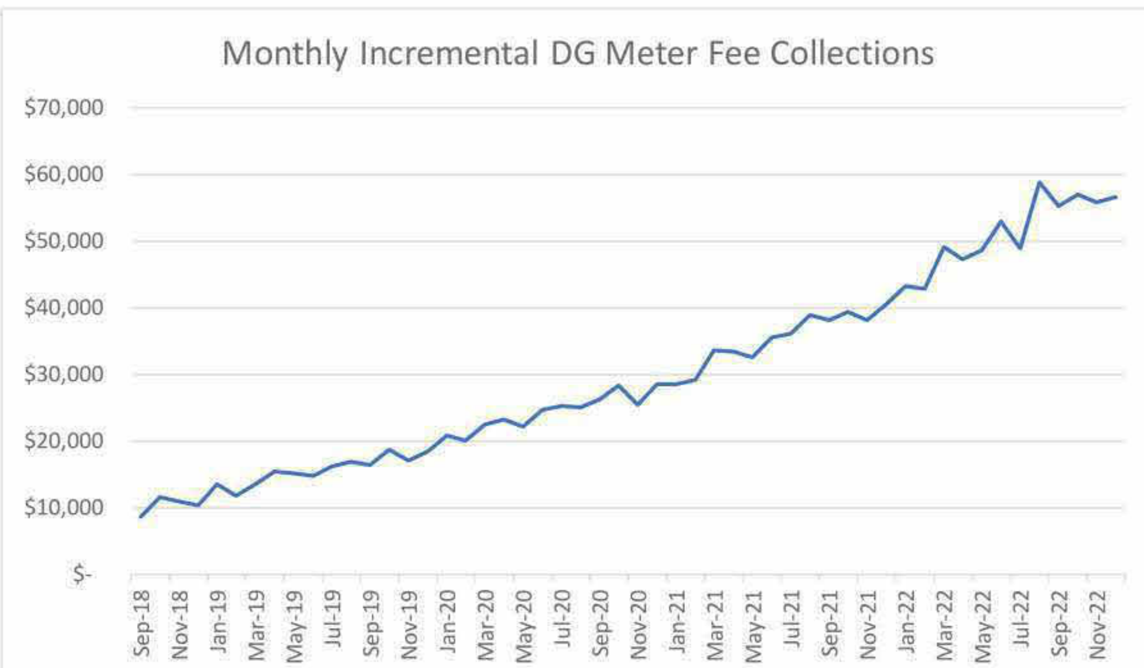

Figure 1 - Monthly Incremental DG Meter Fee Collections

[30] Exhibit KL-21, AriSEIA 10.01e. However, the Company's workpapers for this response for December 2022 show 25,558 total customers were assessed a fee, composed of 25,273 residential and 285 small commercial customers.

[31] Workpaper ARISEIA 10f DG Meter Fee Collection.xlsx.

Q19. WHEN DID THE COMPANY CEASE INSTALLING THE AMR METER THAT WAS THE BASIS FOR THE ORIGINAL INCREMENTAL COST CALCULATION?

A19. The last month with any substantive AMR meter installs was January 2019, when the Company installed 77 AMR meters, down from an installation rate of about 1,500 per month in 2017.[32] This coincides with the approval of the Company's AMI meter rollout approval, which was granted in January 2019.[33]

Q20. WHEN DID THE COMPANY START PLANNING FOR AND INSTALLING AMI METERS?

A20. The Company began planning for an AMI transition in January 2016.[34] It began work on its AMI Pilot program in May 2018 and installed its first batch of 136 AMI meters in June 2018 and another batch of 1,550 AMI meters in August 2018. By the end of 2018, before the AMI meter deployment had even been approved, the Company had installed 7,915 AMI meters.[35] The Company finalized the selection of meters, capabilities, and deployment strategy in December 2018, and won approval to move forward with the deployment in January 2019.[36]

Q21. HOW DOES THIS TIMING ALIGN WITH THE DEVELOPMENT OF FEE?

A21. The timing is critical to understand. It is my understanding that TEP knew or should have known that its bidirectional AMI meters were going to nullify the Fee *before* the fee was approved by the Commission. Even if this were not the case, it absolutely became known when the AMI program deployment was approved in January 2019, only four months after the DG Incremental Meter Fee was approved.

The key dates on this timeline are shown below in Table 1. TEP had installed AMI meters in the summer of 2018, before the Fee was approved but after the Commission made clear that the Fee was only for the incremental cost of the bidirectional meter. TEP knew at this time the capabilities – including the ability to perform bidirectional meter reads – of the

[32] Exhibit KL-22, AriSEIA 9.03j. The Company installed three AMR meters in February 2019, and single AMR meter in June 2019 and July 2019, and none after July 2019.
[33] Exhibit KL-22, AriSEIA 9.03g.
[34] Exhibit KL-22, AriSEIA 9.03f.
[35] Exhibit KL-22, AriSEIA 9.03j.
[36] Exhibit KL-21, AriSEIA 10.01h.

AMI meters it was installing, and therefor knew in summer 2018 that there would be no incremental cost to these meters if the AMI deployment was approved with these meters.

In fact, there was no scenario in which the Company would have moved forward with AMI meters incapable of bidirectional reading. It admitted in discovery that it never had any discussion or consideration of using AMI meters that did not have bidirectional capability, that it never installed a single AMI meter during the pilot that lacked this function, and it never installed a non-bidirectional AMI household meter for any DG customer.[37]

[37] Exhibit KL-23, AriSEIA 13.01, Exhibit KL-24, AriSEIA 13.02.

Date	Action / Event
November 5, 2015	TEP Phase 1 Rate Case filed[38]
January 2016	TEP first contemplates potential AMI transition[39]
September 1, 2016	TEP first quantifies proposed incremental meter fee[40]
February 24, 2017	Commission finds DG Meter Fee should be based on incremental cost of bidirectional meter, not 2nd production meter. Fee set to $2.05/month, to be revisited in Phase II.[41]
May 2018	AMI Pilot program begins[42]
June 2018	First batch of AMI meters installed[43]
August 2018	Second batch of AMI meters installed[44]
September 20, 2018	Commission rejects Company's position and reaffirms its Phase I approach, setting the fee to $2.23/month to "recover only the incremental costs" of the bidirectional meter.[45]
December 2018	AMI Pilot results ready[46]
December 2018	TEP finalizes meter selection and capabilities[47]
January 2019	Full AMI meter deployment approved[48]
January 2019	Full AMI meter deployment begins[49]
Jan 2019 – Feb 2023	TEP charges customers more than $1.5 million for a fee which has no cost basis
February 15, 2023	TEP admits in rebuttal that the fee has no basis and that it will cancel it going forward.[50]
February 15, 2023 – September 1, 2023	TEP proposes to continue collecting the Fee despite admitting it has no basis.[51]

Table 1 - Key Dates on AMI Deployment and Fee Development

The Company stated that because the Fee was approved by the Commission, it should not have to refund customers for baseless charges. This claim cannot stand up to scrutiny. While the Company may have a weak claim that DG meters installed after the Fee was approved in September 2018 but before the AMI rollout was approved in January 2019 could

[38] Lucas Direct at 375.
[39] Exhibit KL-22, AriSEIA 9.03f.
[40] Lucas Direct at 375
[41] Order 75975 at 155, Docket Nos. E-01933A-15-0239, E-01933A-15-0322, February 24, 2017. Accessed at https://docket.images.azcc.gov/0000177572.pdf.
[42] Exhibit KL-22, AriSEIA 9.03f.
[43] Exhibit KL-22, AriSEIA 9.03j.
[44] Exhibit KL-22, AriSEIA 9.03j.
[45] Order 76899 at 98, Docket Nos. E-01933A-15-0239, E-01933A-15-0322, September 20, 2018. Accessed at https://docket.images.azcc.gov/0000192323.pdf
[46] Exhibit KL-22, AriSEIA 9.03f.
[47] Exhibit KL-2, AriSEIA 10.01h.
[48] Exhibit KL-22, AriSEIA 9.03f.
[49] Exhibit KL-22, AriSEIA 9.03f.
[50] Dang Rebuttal at 7.
[51] Exhibit KL-25, AriSEIA 12.01

have theoretically involved an incremental cost, this justification was completely discredited as soon as the AMI program was approved. From January 2019 forward, DG and non-DG AMI meters were functionally identical in terms of bidirectional meter capability and the Fee should have been cancelled then.

Q22. WHY DID THE COMPANY NOT EXPLAIN THIS CHANGE IN CIRCUMSTANCES TO THE COMMISSION?

A22. It is unclear, although there is an obvious benefit for the Company from its failure to do so. From January 2019 through December 2022, the Company collected $1.52 million in Fees, and continues to bring in roughly $55,000 per month in revenue. This is pure profit to the Company as there is no corresponding cost to offset these revenues.

Q23. DOES THE COMPANY PROPOSE TO CANCEL THE FEE EFFECTIVE IMMEDIATELY?

A23. No, it does not. The Company proposes to cancel the fee only when the base rates from this docket become effective, [52] which it proposes be "no later than September 1, 2023."[53] So despite having fully admitted that the fee is unjust in the middle of February 2023, TEP desires to collect the Fee for another six and a half months. At the current run rate, this would be equal to roughly another $350,000.[54]

Q24. DID THE COMPANY HAVE AN EXPLANATION FOR WHY IT HAS DELAYED INFORMING THE COMMISSION THAT THE FEE IS NO LONGER VALID?

A24. Yes, it did. TEP indicated that while "there is a cost basis for all the Company's service fees," it caveats this by continuing "*at the time the fees were approved by the Commission*."[55] TEP reviews its fees during its rate cases, stating "The Company reviews the underlying cost structure the fees are based on and modifies the price if needed."[56] In this case, it recommended

[52] Exhibit KL-25, AriSEIA 12.01.
[53] TEP Application at 1.
[54] $55,000/month * 6.5 months. In reality, DG installations continue to increase, so the actual Fees collected would be higher.
[55] Exhibit KL-26, AriSEIA 13.03.
[56] *Id.*

increasing three fees and reducing 10 fees.[57] Notably, the DG Incremental Meter Fee was not one that was recommended for reduction or elimination.

Q25. DID TEP PROVIDE ANY REASON FOR WHY THE FEE WAS OVERLOOKED IN ITS REVIEW OF THE COST BASIS OF ITS SCHEDULE OF FEES?

A25. No, it did not.

Q26. DOES TEP HAVE AN OBLIGATION TO INFORM THE COMMISSION ABOUT CHANGES IN CIRCUMSTANCES RELATED TO ITS FEES, SUCH AS A CHANGE THAT RENDERS A FEE OBSOLETE?

A26. According to the Company, "The Company is not aware of any specific obligation to notify the ACC if one of its fees is based on outdated information."[58]

Q27. GIVEN THE PREPONDERANCE OF EVIDENCE THAT THE COMPANY KNEW THE FEE WAS OBSOLETE AS SOON AS THE AMI DEPLOYMENT WAS APPROVED, HOW DOES IT CONTINUE TO JUSTIFY NOT REFUNDING THESE FEES TO THE DG CUSTOMERS?

A27. TEP objected to this question, claiming that it "seeks a legal opinion."[59] Nonetheless, it continued:

> Notwithstanding that objection in Arizona, rates and charges are set based on a historical test year. The fee was based on a Commission decision which was made utilizing the best information at that time. Like any other service fee and rate changes, this change should be made on a going forward basis upon Commission approval.[60]

Q28. WHAT IS YOUR RESPONSE TO THIS?

A28. Is it unsurprising. I do not believe that the Fee was based on a Commission decision which was made "utilizing the best information at the time." The Company admitted through discovery that it knew during the proceeding that established the Fee that it would be rendered obsolete by the proposed AMI deployment. Despite this, the Company did not provide this information during that proceeding, maintaining instead that the fee should be based on the incremental cost between a bidirectional meter and the soon-to-be-defunct AMR meter.

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[57] *Id.*
[58] *Id.*
[59] *Id.*
[60] *Id.*

Whether this constitutes a breach of judgement, protocol, or regulations will be up to the Commission to determine.

Q29. ARE YOU SURPRISED BY TEP'S FAILURE TO PROVIDE THIS INFORMATION IN THE PRIOR CASE, OR BY ITS FAILURE TO IDENTIFY THE FEE FOR ELIMINATION?

A29. The failure to identify this Fee for elimination is particularly troubling given that the stated reason for the reduction of many other fees is directly attributable to AMI: "The Company is proposing to decrease the majority of the Company's service fees. These decreases are driven by the reduced cost of providing these services resulting from deployment of the Company's AMI metering technology."[61]

While it is concerning, I am not surprised. TEP is a for-profit, investor-owned monopoly that seeks to maximize its profits while providing the requisite utility services to its customers. Under this structure, strong regulation is required to prevent monopolies from exercising market power over captive customers, such as charging DG customers for more than four years for a fee that is completely unjustified and without merit. The Commission should send a strong signal that knowingly turning a blind eye to baseless fees will not be tolerated and should require regulated utilities to notify it of over-collections.

Q30. WHAT DO YOU RECOMMEND REGARDING THE FEE?

A30. My recommendation is that the Commission fully refund all Fees charged to all DG customers from January 2019 forward, including any collected by the Company in 2023 before rates from this case go into effect. The Company clearly knew or should have known before the Fee was approved that it would be rendered moot by its AMI deployment. Despite this, the Company did not provide this information in that case even though it was known at the time.

Any lingering questions regarding the potential denial of the AMI deployment and the continued reliance on AMR meters for non-DG customers was eliminated with the approval of the AMI deployment in January 2019. From that moment on, the incremental cost on which

[61] Dang Direct at 14.

the Fee was predicated vanished. Every dollar that was collected after that approval was unjust and unreasonable and should be credited back to customers.

IV. REBUTTAL TO RICHARD D. BACHMEIER REGARDING THE COMPANY'S TOU RATE DESIGN AND ITS ANALYSIS OF DEMAND RATE BILL IMPACTS

Q31. PLEASE SUMMARIZE THE TESTIMONY THAT YOU PROVIDED RELEVANT TO MR. BACHMEIER'S REBUTTAL ON TOU RATE DESIGN AND DEMAND-BASED RATES.

A31. I analyzed the Company's current and proposed TOU rates and determined they are currently very weak and would remain weak even after proposed changes. TEP's current summer and non-summer peak ratios for the RES-T tariff is 1.29 and 1.05, respectively. If its proposal is approved, the summer ratio will rise slightly to 1.51 while the non-summer remains unchanged.[62] These rate differentials are insufficient to drive behavior change; I calculated that a customer that shifts 10% of their peak load (a non-trivial amount) would save $0.32 per month under the current tariff, and about $0.68 per month on the proposed tariff.[63] These are simply insufficient levels to drive meaningful behavior changes.

I also testified that TEP's residential demand-based rates, while voluntary, should be closed to new customers.[64] I argued that customers do not really understand the differences between demand and energy, and while TEP's rates contain elements that are preferable to other utilities' demand-based rates (such as measuring demand only during peak hours and making it voluntary for all customers), I do not believe demand-based rates are appropriate for residential customers and that volumetric TOU rates send more accurate and more actionable price signals.[65]

Q32. WHAT WAS TEP'S RESPONSE TO YOUR TESTIMONY?

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[62] Lucas Direct at 357.

[63] Lucas Direct at 318. The rate differentials on the new tariff increase to $0.0802/kWh for summer and $0.0078/kWh for winter peak. Shifting 10% of peak energy based on the average usage produces ((185 * 10% * $0.0802) * 5 + (134 * 10% * $0.0078) * 7) / 12 = $0.679

[64] Lucas Direct at 320.

[65] Lucas Direct at 321.

A32. TEP witness Bachmeier was "puzzled" by my assertion that the Company's rates were complex, countering that "they are quite simple to understand."[66] He opined that rates that combined including block rates and TOU components are "far from unusual,"[67] and that inclining block rates serve to send a price signal for conservation and energy efficiency at high usage levels and assist low-income, low-usage customers with electric service affordability.[68] Mr. Bachmeier also pointed out that I combined margin and base power energy charges, which "conceals the fact that these energy charges recover revenue from two different sources."[69]

Mr. Bachmeier did not agree with my and other intervenor recommendations to develop a more robust on-peak ratio for the volumetric TOU rates. He reiterated the Company's proposal to increase the summer peak ratio for the base power portion of the rate from 2.5 to 3.5, concerned that extending the higher TOU differential to the margin component would impact the risk associated with revenue collection and revenue stability.[70]

Mr. Bachmeier also defended TEP's demand-based rates, assuming – with no evidence – that customers taking service on those rates "understand the difference between energy and demand and prefer a service on a demand rate."[71] He also conducted an analysis that purported to show that customers taking service on demand rates are not structurally benefitting from those rates.[72]

Q33. WHAT IS YOUR RESPONSE TO TEP'S REBUTTAL TESTIMONY?

A33. I will take each issue in turn. Regarding Mr. Bachmeier's comments on the structure of TEP's rates, my observation about the rates being complex was from the perspective of the customer, not a rate analyst. Clearly Mr. Bachmeier and I are perfectly capable of understanding TEP's rates, and we would not have a problem interpreting a bill on the Electric Vehicle ("EV") TOU

[66] Bachmeier Rebuttal at 16.
[67] *Id.* at 17.
[68] *Id.* at 17.
[69] *Id.* These are "margin" revenue which includes the return on and of assets plus non-fuel operational expenses, and "base power" charges which includes fuel and purchased power costs.
[70] *Id.* at 18.
[71] *Id.* at 24.
[72] *Id.* at 25.

tariff that contains three inclining block rates and three TOU periods, each of which varies by month and day of the week. But he and I are not typical consumers of electricity, and I would posit that most of TEP's customers know less about rates and rate design than the two of us.

To figure out what the next kWh of usage would cost a customer, they must know 1) what rate they take service under, 2) how much energy they have used so far in the billing period, 3) what time the usage will occur, 4) what day of the week the usage will occur, 5) what month it is, and 6) whether it a holiday. This surely lands more squarely in the "complex" than "quite simple" realm as Mr. Bachmeier claims.

Q34. WHAT ABOUT CLAIMS THAT COMBINED TOU/INCLINING BLOCK RATES ARE "FAR FROM UNUSUAL"?

A34. Mr. Bachmeier asserts without proof that TOU rates combined with inclining block rates are "far from unusual," citing two papers that suggest these rates can exist and pointing to examples in California and Oregon.[73] But the fact that some utilities (including TEP) implement these rates does not demonstrate they are widely deployed. To validate this, I examined the OpenEI Utility Rate Database ("URD"), a public repository of utility rates.[74]

The complete URD database currently contains 50,066 entries from 2,826 municipal, coop, and Investor Owned Utilities ("IOU") utilities, each representing a different utility tariff. Of these, 30,145 are active, and of those, 6,126 are listed as "residential" tariffs. I examined the structure of these residential tariffs and found that 2,332 rates had an inclining or declining block structure, and 811 had some TOU component.[75] However, only 51 tariffs from 33 utilities (out of more than 6,000 active residential tariffs from 2,600 utilities) contained both TOU and inclining/declining block structures, making these rates, in fact, "somewhat unusual."[76]

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[73] Bachmeier Rebuttal at 17.
[74] National Renewable Energy Laboratory, United Stated Utility Rate Database, Open EI (Mar. 5, 2023, 1:58 PM), https://apps.openei.org/USURDB/.
[75] This excludes tariffs that had seasonal rates but had flat pricing within a given month.
[76] Tariffs with specific customer qualifications (e.g., geographic regions in California and one or three phase service in Hawaii) were counted as one tariff.

Q35. WHAT ABOUT THE PURPOSE AND FUNCTION OF INCLINING BLOCK RATES?

A35. Mr. Bachmeier testified that inclining block rate structures send a price signal for conservation and energy efficiency at high usage levels and assist low-income, low-usage customers with electric service affordability.[77] While these assertions are correct, it does not mean that this rate design is the best way to implement these policy goals.

High usage is not in and of itself a problem. In fact, policy makers across the country – including those in Arizona – recognize the myriad benefits of beneficial electrification ("BE") in meeting decarbonization and other policy goals.[78] BE's primary vector is the electrification of transportation loads (i.e., electric vehicles replacing gas-powered cars and trucks) and building heating loads (e.g., space and water heating). Inclining block structures are anathema to BE; a much better solution is TOU rates that send price signals to increase electricity usage during key hours such as midday when solar is plentiful and overnight when system loads are low. In fact, TEP already implements EV rates that target overnight charging (although these rates are hampered by the inclusion of inclining block pricing for base power charges, as other intervenors pointed out[79]).

Similarly, other policy mechanisms – including some already implemented by TEP – exist to assist low-income customers. TEP has a number of lifeline rates that provide discounts on monthly electricity bills. If there is concern that undoing the inclining block structure would put too much pressure on low-usage, low-income customers, the lifeline discount could be adjusted.

Q36. WHAT ABOUT THE OBSERVATION THAT COMBINING RATE ELEMENTS CONCEALS THAT BASE AND MARGIN REVENUE ARE COLLECTED FROM DIFFERENT RATE COMPONENTS?

A36. This observation by Mr. Bachmeier is correct but irrelevant. A typical TEP customer is unlikely to differentiate between base and margin charges as they are responsible for their

[77] Bachmeier Rebuttal at 17.
[78] Arizona Technology Council, Arizona Electrification Summit Convenes Energy Leaders, SignalsAZ.com (Mar. 5, 2023, 2:01 PM), https://www.signalsaz.com/articles/arizona-electrification-summit-convenes-energy-leaders/.
[79] See Bachmeier Rebuttal at 21 discussing WRA/SWEEP testimony on EV rates.

entire bill, not just a portion of it. TEP's residential bill breaks down delivery, power supply charges, surcharges, and taxes and assessments "for ease of skimming," [80] but the customer's focus is almost certainly on the total monthly bill.

Similarly, TEP does not separately account for base and margin revenue at the corporate level. While fuel and purchased power is broken out on the Company's financial statements, revenue is presented in a total, consolidated manner.[81] Further, the Company does not have a revenue decoupling mechanism that treats base and margin revenue differently.[82] Simply, revenue dollars – whether collected through one part of the rate or another – are completely fungible within the organization.

Q37. WHAT IS YOUR RESPONSE ABOUT NOT EXTENDING TOU RATES TO THE BASE RATE COMPONENT?

A37. Mr. Bachmeier points out that extending TOU rates to the base rate component instead of limiting them to power supply charges puts pressure on revenue collection and revenue stability. I agree that this may happen, but these are only some of the considerations that the Commission should weigh when analyzing this issue.

Revenue stability and adequacy are two of the rate design criteria in the oft-cited Bonbright Principles.[83] These must be considered with other ratemaking principles such as gradualism, simplicity, understandability, and efficiency. As it stands, the Company's TOU rates are not particularly simple or understandable, nor are they very efficient.

As Mr. Bachmeier states, "numerous studies have been undertaken to estimate the peak demand reduction potential from TOU rates."[84] One such study, which updates an analysis referred to by WRA/SWEEP witnesses, demonstrates that higher peak/off-peak ratios result in

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[80] Have a Question? Find out the answer on your new TEP bill; Tucson Electrical Power (Mar. 5, 2023, 2:04 PM), https://www.tep.com/newbill/.
[81] Exhibit KL-27, AriSEIA 12.02a.
[82] Exhibit KL-27, AriSEIA 12.02b.
[83] James C. Bonbright, Albert L. Danielsen & David R. Kamerschen, Principles of Public Utility Rates, (Public Utilities Reports, 2nd edition (March 1, 1988)), *available here* https://www.raponline.org/wp-content/uploads/2016/05/powellgoldstein-bonbright-principlesofpublicutilityrates-1960-10-10.pdf.
[84] Bachmeier Rebuttal at 19.

much deeper peak usage reductions. Further, pairing the rate with enabling technology, such as smart thermostats or in-home displays, drives even greater reductions. Figure 2 below shows the peak usage reduction of TOU rates in a meta-study of more than 330 TOU tariffs.[85]

Figure 14: The Arc of Price Responsiveness

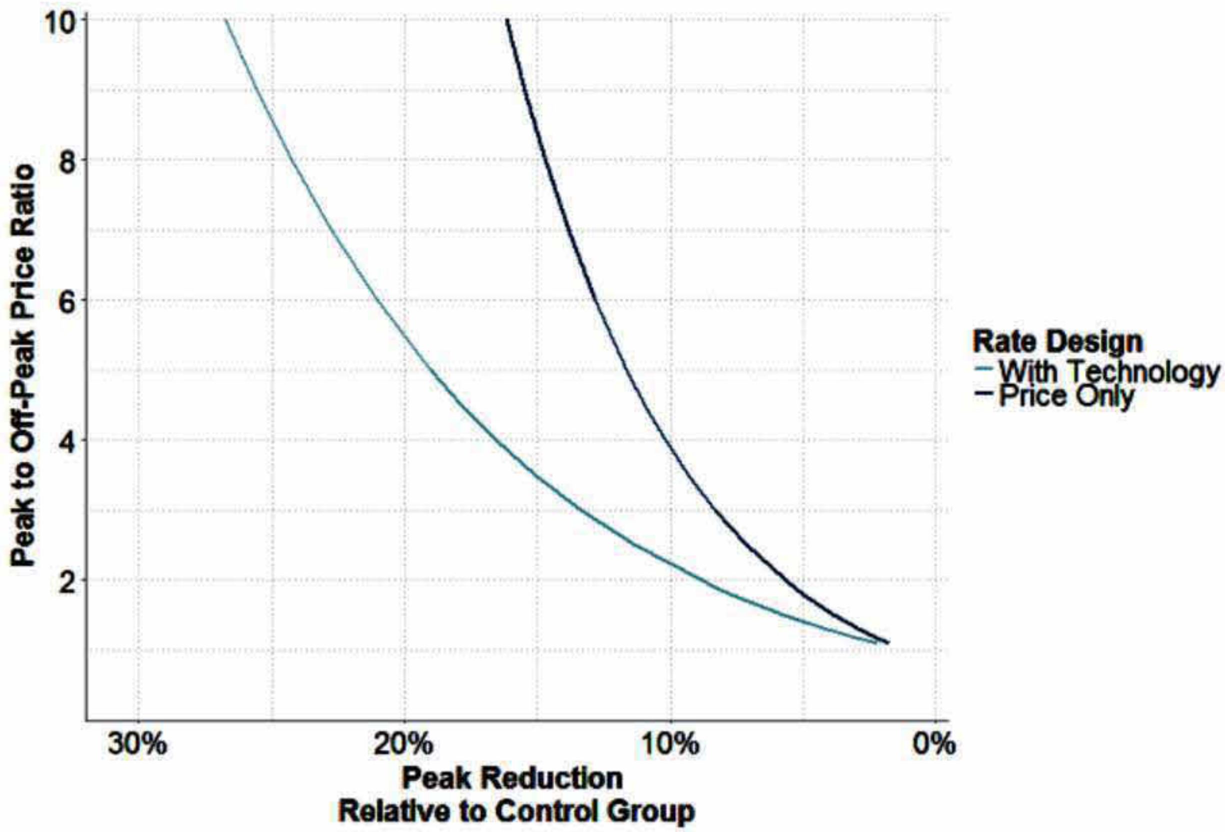

Figure 2 - Arc of Price Responsiveness

TEP's proposed TOU rate will have a peak/off-peak ratio of 1.5 in the summer, which, based on this plot, would translate into roughly a 6% or 4% peak usage reduction with or without enabling technology, respectively. However, increasing the ratio to 3.0 as I recommend would roughly double peak usage reductions to about 13% or 8% with or without

[85] Ahmad Faruqui, Sanem Sergici & Cody Warner, Arcturus 2.0: A Meta-Analysis of Time-Varying Rates for Electricity, (The Electricity Journal, Volume 30, Issue 10, (2017)), *available at* https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/electric-rates/2017-electric-rate-forum/2017-arcturus-2-0-10122017.pdf.

enabling technology, respectively. The incremental benefit of these additional on-peak usage reductions is meaningful and should be pursued.

Other policies exist for addressing revenue adequacy and stability. In the test year, only 8.1% of total residential revenue comes from TOU customers, which naturally limits exposure of the Company to revenue shortfalls from a more progressive TOU rate.[86] TEP indicated it does not have a revenue decoupling mechanism,[87] although it does have a Lost Fixed Cost Recovery ("LFCR") charge for recovering revenue shortfalls attributable to energy efficiency and renewable energy.[88] If revenue sufficiency concerns are serious enough, the Commission could consider expanding the LFCR to include TOU rate revenue erosion. Given that peak usage reduction avoids some of the most expensive energy and can defer or prevent future capacity infrastructure needs, the tradeoff is well worth it.

Q38. PLEASE EXPAND ON MR. BACHMEIER'S TESTIMONY REGARDING DEMAND-BASED RATES.

A38. Mr. Bachmeier provided relatively extensive rebuttal on my testimony regarding demand-based rates. He opens by stating:

> The assertion that most residential customers do not have a strong understanding of the difference between energy and demand is not a good reason to stop offering an optional demand rate. At the end of the test year TEP had almost 8,300 customers taking service on a residential demand rate out of a total of approximately 400,000 residential customers, or about two percent of all residential customers. I assume that these 8,300 or so residential customers understand the difference between energy and demand and prefer service on a demand rate.[89]

Q39. DID MR. BACHMEIER HAVE ANY SUPPORT FOR HIS CLAIM THAT CUSTOMERS UNDERSTAND THE DIFFERENCE BETWEEN ENERGY AND DEMAND AND THUS PREFER SERVICE ON A DEMAND RATE?

A39. No, he did not. TEP has no customer surveys on the understanding of demand-based rates, nor any analysis that shows these 8,300 customers are in fact better off on a demand-based rate.

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[86] Exhibit KL-27, AriSEIA 12.02c.
[87] Exhibit KL-27, AriSEIA 12.02b.
[88] Lost Fixed Cost Recovery Charge; Tucson Electrical Power (Mar. 5, 2023, 2:04 PM), https://www.tep.com/lfcr/.
[89] Bachmeier Rebuttal at 24.

Rather, "Mr. Bachmeier's support for the statement is the assumption in Economic Theory that consumers are rational economic agents."[90]

The notion that individual consumers are rational economic agents and go through life making a series of analytical cost/benefit tests on everyday matters is increasingly falling out of favor. This concept – man as *homo economicus* or "economic man" – assumes people act in a consistently rational and narrowly self-interested way to pursue their subjectively defined ends optimally.[91] While this might be a useful rubric in economic theory, it is clearly not how individuals actually behave. The field of behavioral economics has emerged in the past several decades to rebut this framing. Rooted in the exploration of cognitive biases and the tendency to use societally influenced heuristics in decision making, behavioral economics shows how real-world decisions and decision-making diverges from classical economic theory. One need not look further than the existence of the lottery and Las Vegas to realize that consumers are not always rational economic agents.[92]

Q40. MR. BACHMEIER PRODUCED A STUDY SUGGESTING THAT HIGH-USE CUSTOMERS DO NOT SAVE MUCH MONEY ON DEMAND CHARGES. DID YOU REVIEW THIS ANALYSIS?

A40. Yes, I did. Mr. Bachmeier produced this analysis in response to my testimony that customers who take service on demand charges are likely to have a structural advantage such that they could save money on that rate without changing their underlying electricity consumption. He concludes "AriSEIA's contention that higher usage residential customers will pay less on demand rates than they do on volumetric rates is not accurate. Demand rates do not reward higher usage, they reward higher load factors, resulting in more efficient use of the electric system."[93]

Q41. PLEASE DESCRIBE THE ANALYSIS THAT MR. BACHMEIER PRODUCED TO SUPPORT HIS CONCLUSIONS.

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[90] Exhibit KL-28, AriSEIA 12.03a.

[91] https://www.behavioraleconomics.com/resources/mini-encyclopedia-of-be/homo-economicus/

[92] Ambrose Bierce, Lottery: A tax on people who are bad at math, (The Unabridged Devil's Dictionary, University of Georgia Press (2002)).

[93] Bachmeier Rebuttal at 25.

A41. Mr. Bachmeier took a subset of the Company's original bill impact analysis[94] to produce a new analysis that focused on specific residential tariffs.[95] Like the original bill impact analysis, this one calculates a hypothetical bill under four residential tariffs for different size customers. The summary of the results is shown below in Figure 3, showing the change in bill from the basic rate ("RES"), the Time of Use plan ("REST"), the Peak Demand rate ("RESD"), and the Demand TOU rate ("RESDT"). Values are shown based on the percentile usage that mirrors those used by the Company in the bill impact analysis.

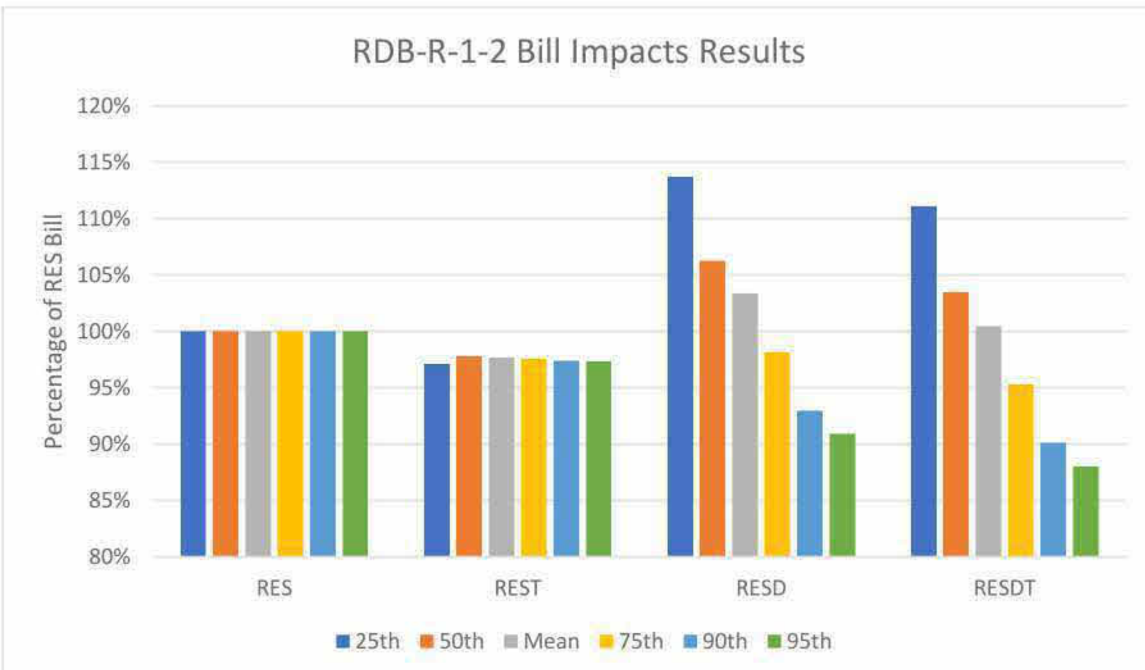

Figure 3 - RDB-R-1-2 Bill Impacts

For this set of modeled customers, those on the standard TOU rate saved about 2-3% across the board. This is not surprising as the Company's analysis assumes that peak energy use is constant as usage increases, although it offers no support for this assumption. However, the relationship I described in my testimony – that high use customers are structurally advantaged on demand rates – is clearly evident here. As seen in both the RESD and RESDT rate, low use customers paid more and large use customers paid less.

[94] 2021 TEP Schedule H-4
[95] TEP 2022 Exhibit RDB-R-1-2 Bill Impacts

Q42. DID. MR. BACHMEIER HAVE AN EXPLANATION FOR THIS?

A42. Yes, he did:

> At a glance, this may support the assertion that higher usage customers will pay lower bills on demand rates, but it does not tell the whole story[.] In fact, TEP's residential demand rates are designed to become economical for customers as their monthly on-peak load factor approaches and exceeds 30 percent, depending on usage. The lesson here is that TEP's residential demand rates as currently structured encourage reducing on-peak usage and improving on-peak load factors, both of which provide system benefits and reduced costs.[96]

Q43. DID MR. BACHMEIER PROVIDE ADDITIONAL DATA TO SUPPORT THESE STATEMENTS?

A43. No, he did not.

Q44. PLEASE DESCRIBE COMPANY'S BILL IMPACT ANALYSIS METHODOLOGY.

A44. The Company used test year billing data to determine usage levels at different percentiles for each tariff.[97] The Company used hardcoded summer and winter peak usage percentages that do not vary based on customer size to calculate TOU period usage on tariffs that contain TOU rates.[98] For tariffs with demand rates, the Company calculated a load factor for a given usage level based on a fitted exponential power function.[99] Once all of the components (seasonal usage, TOU usage, and peak demand) were calculated, the total bills under the current and proposed rates were calculated for each tariff.

Q45. WERE YOU ABLE TO TRACE THE ORIGIN OF THE PEAK USAGE PERCENTAGES?

A45. No, I was not. The Company's values for these key metrics are hardcoded. Further, they do not appear to correspond to other workpapers. I reviewed multiple workpapers that contained information about peak and off-peak usage and was not able to duplicate these values. A summary of the results of this investigation are show below in Table 2.

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[96] Bachmeier Rebuttal at 25.

[97] For example, the 75th percentile customer on the TRREST tariff used an average of 1,074 kWh per month.

[98] Residential customers were all assumed to have 16.5% and 19.9% of summer and winter usage, respectively, during peak TOU periods. TEP 2022 Exhibit RDB-R-1-2 Bill Impacts

[99] Specifically, Billing LF = a*kWh^b, where *a* and *b* are constants that vary by class and season.

Source	Workpaper	Summer Peak	Winter Peak
Bill Impact Analysis	2021 TEP Schedule H-4	16.5%	19.9%
Discovery	ARISEIA 8.01 TEP RES Load Data	14.58% (all) 16.13% (no 0s)	19.55% (all) 19.85% (no 0s)
Hourly Loads	2021 Hourly Class Data	17.49%	19.82%
Billing Adjustments	Determinants and Adjustments for 2022 Rate Case	16.30%	18.67%

Table 2 - Peak Usage Statistics from Various Sources

Q46. DO YOU HAVE EXPLANATIONS FOR SOME OF THESE DISCREPANCIES?

A46. Yes, some are explainable. The Company made a series of adjustments to sales for factors such as weather, customer growth, and uncollected revenue. The values from the Hourly Loads file and Billing Adjustment files do not include these adjustments, but they are also not equal to each other.[100] The AriSEIA 8.01 discovery workpaper utilizes data from 2013/2014 and would not be expected to match the test year. Still, it is frustrating that the Company simply hardcoded a value with no source data to trace what type of values (e.g., actual billing, weather adjusted values, etc.) were used for this analysis.

Q47. CAN YOU DISCUSS HOW THE DEMAND VALUES WERE DERIVED?

A47. Yes. The parameters discussed above to calculate the load factors were also hardcoded in the Company's workpapers, so I asked discovery questions to determine their origins.[101] The Company provided workpapers that calculated this and other values by analyzing the monthly usage of about 17,000 residential customers. Averages for usage, peak demand, and on peak usage were calculated across the dataset. An average of average demands was subsequently calculated for usage blocks, which was then used to calculate summer and winter load factors.[102] These values were then used to fit an exponential trendline to produce the

[100] The Billing Adjustment worksheet applies the various adjustments, but only to total usage and not to the peak/off peak usage. Those values match the unadjusted billing data values found in that workpaper.
[101] Exhibit KL-29, AriSEIA 8.01 Supplemental.
[102] For instance, the average kW demand for customers with an average monthly usage between 250 and 350 kWh per month was calculated and matched with 200 kWh per month usage.

coefficients used to calculate load factors in the bill impact analysis.[103] Finally, the billing demand was calculated from the load factor and the monthly energy usage.

The workpaper was originally created in 2011 and uses load data from 2014/2015. At this point, these values are very out of date as the relationship between energy and demand has changed with the continued deployment of more efficient appliances and changes in building codes. Additionally, the workpapers provided contained several issues that impacted the calculation of these values.

- Average load and demand calculations included months with 0 values, depressing those results. Nearly 20% of customers had months with 0 value, resulting in a meaningful reduction in average usage and demand values.[104]
- The formula that aggregated demand values for usage blocks incorrectly calculated the first block value for 100 kWh, causing the entire fitted power curve to shift.[105]
- The "average of average" approach hides the substantial variation in customer load factors, making the Company's fitted power curve appear more robust than it is.[106]
- The Company extends the demand binning all the way to 4,500 kWh per month, placing too much emphasis on rare, very high use customers.[107]

Q48. DID YOU ATTEMPT TO RESOLVE THESE ISSUES?

A48. No, I did not. The Company's prior approach of using what appears to be pre-AMI load research data for calculating these metrics is outdated. Given the sizable number of AMI meters and many years of billing history the Company has amassed, it should shift to utilizing

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[103] The final summer equation is Load Factor = 0.053257 * kWh ^ 0.255510, while the winter equation is Load Factor = 0.026953 * kWh ^ 0.334931

[104] Eliminating customers with 0 values increases the average usage from 8.844 kWh / year to 9.538 kWh / year and average demand from 3.67 kW to 3.94 kW.

[105] The calculations binned customers by usage between the midpoints of the step above and below. For instance, the value for the 300 kWh bin contained customers from 250 kWh to 350 kWh. However, the workpaper omitted the 0 above the 100 kWh value, so rather than calculating customers between 50 and 150 kWh, the formula calculated the value for customers between 100 and 150 kWh.

[106] The Company's load factor curve fit shows an R^2 value of 0.9655 for summer and 0.8893 for winter, suggesting very good fits. However, the relationship between individual customers' usage and load factors is much less robust, as discussed below.

[107] 95% of customers have an average summer usage below 2,200 kWh. By extending the binning and subsequent curve fit to 4,500 per month, the Company places as much weight on the highest 5% usage customers as on the remaining 95% of customers. A much better fit is possible by using a linear regression for between 200 kWh and 2,200 kWh, which eliminates outliers while representing the middle 90% of customers.

actual billing data from customers rather than calculating projected load factors using a sample of meters.

Q49. Were you able to use the billing data in this workpaper to validate Mr. Bachmeier's claim that TEP's demand rates reward high load factor customers?

A49. Yes, I was. I used the individual customer data to reproduce hypothetical bills on the four tariffs listed above using the Company's proposed rates from its rebuttal testimony.[108] While the underlying data is quite old, and customer usage profiles likely have shifted in the 7-8 years since this data was collected, it represents the best (and only) data sample of this type in the record.

Q50. What did you find in this analysis?

A50. I found that load factor increases with usage – about 0.6% for every 100 kWh of incremental average usage – although there are plenty of lower-usage customers that have high load factors. The relationship, shown in Figure 4 below, reveals the true diversity of individual residential customers on the Company's system that was hidden by the Company's binned average calculation approach discussed above.[109] This is a critical element of rate design, discussed shortly.

[108] I eliminated the roughly 20% of customers with 0 usage monthly readings and did not include June bills for roughly 2,000 remaining customers that were missing June peak usage values. The bill impact represents the average monthly bill for all months where June data was complete and for 11 months where June data was unavailable.

[109] The R^2 for the linear fit for all customers is only 0.150, compared to the 0.89 and 0.96 for the Company's fits. The linear fit was better than the power fit ($R^2 = 0.098$)

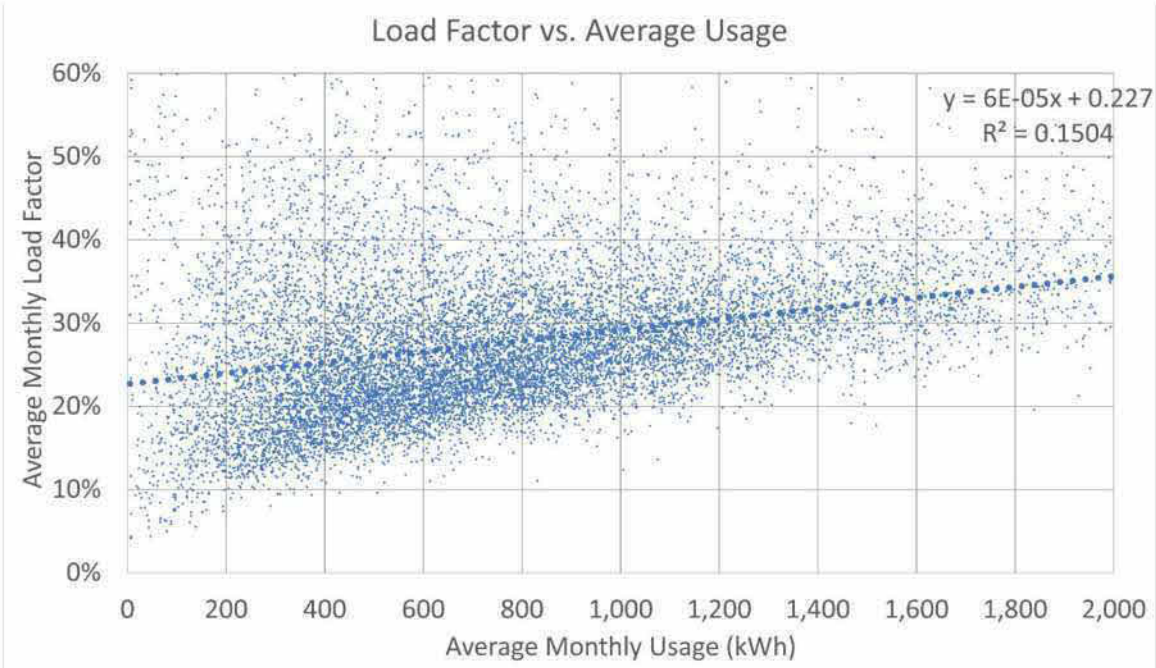

Figure 4 - Load Factor vs. Average Usage

I also confirmed Mr. Bachmeier's assertion that TEP's demand rates do benefit customers with high load factors, independent of their usage, and that the benefit tends to kick in as load factors approach and exceed 30%. Figure 5 below shows the percentage bill impact between the RES and REST tariff (blue), the RES and RESD tariff (orange), and the RES and RESDT tariff (grey). As with Figure 3 above, these customers do slightly better on the REST across range of load factors, suggesting a lack of revenue-neutrality between these rates. However, there is a strong trend with the two demand-based rate options, with lower load factor customers paying substantially more and higher load factor customers attaining significant savings.

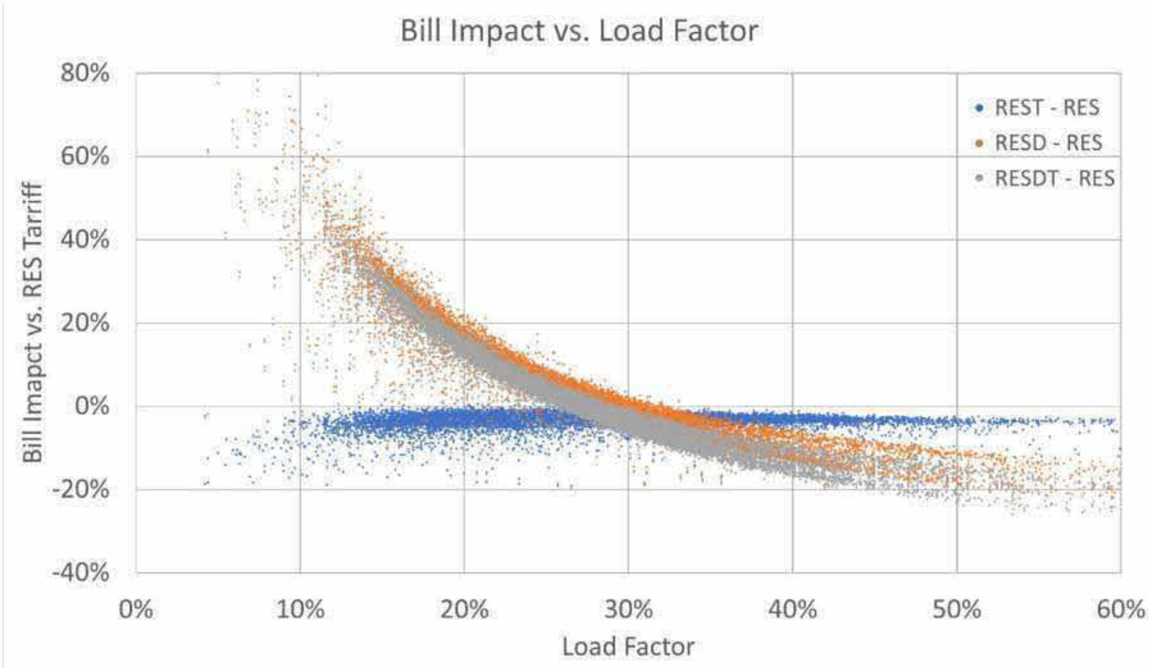

Figure 5 - Bill Impact vs. Load Factor

Q51. WAS IT ALSO THE CASE THAT HIGH-USE CUSTOMERS SAVED MONEY ON DEMAND-BASED RATES AS YOU TESTIFIED?

A51. Yes, it was. I compared bills for the top 10% of customers by usage, a set which consisted of 1,332 customers. The average bill for these customers on the RESD and RESDT rates were 9% and 12% lower than the RES tariff, respectively, and 6% and 9% lower than the REST tariff, respectively. Further, of the 1,332 customers in this set, 1,208 had the lowest bill on the RESDT rate while the RESD tariff produced the 2nd lowest bill for 1,114 of these customers. Notwithstanding Mr. Bachmeier's claims to the contrary, high-use customers do in fact save money on the Company's demand rates.

Q52. GIVEN YOU HAVE BOTH CONFIRMED MR. BACHMEIER'S STIPULATION THAT DEMAND RATES BENEFIT HIGH LOAD CUSTOMERS AND REAFFIRMED YOUR TESTIMONY THAT THEY BENEFIT HIGH-USE CUSTOMERS, DO YOU STILL THINK DEMAND-BASED RATES SHOULD BE CLOSED FOR NEW CUSTOMERS?

A52. Yes, I do.

Q53. PLEASE EXPLAIN WHY YOU CONTINUE TO BELIEVE THIS.

A53. Granting Mr. Bachmeier's position that high load factor customers benefit on the Company's demand-based rates, it is worth testing his assertion that these rates "encourage reducing on-peak usage and improving on-peak load factors, both of which provide system benefits and reduced costs."[110]

I agree that attaining higher load factors at the system or class level is beneficial and allows the system as a whole to serve more load without a corresponding increase in costs. This is because the marginal cost of energy is typically lower than the marginal cost of capacity, whether distribution capacity to serve residential loads or generation or transmission capacity to serve all loads.[111] But it does not follow that increasing the load factor of an individual customer necessarily leads to system benefits.

The Company's demand rates apply year-round and are based on billing demand during peak TOU windows. These windows – weekdays 6 to 9 AM and 6 to 9 PM in the non-summer and 3 to 7 PM in the summer – are intended to correspond to the hours in which the system is under stress through high loads or facing high energy costs. However, the Company's system is strongly summer peaking, with ample spare capacity in winter and shoulder months. A customer that attains a high load factor in March is doing nothing to eliminate costs or provide system benefits compared to a customer with a low load factor in March – there is ample spare capacity throughout the system to serve both customers equally. Given this, why should the high load factor customer be rewarded through demand-based rates?

Likewise, even during summer months when the system could be under stress, a customer's demand is based on their single highest hour of load within the monthly TOU window. But many of these weekday windows do not contain the actual peak loads of the system, and unless a customer sets their peak demand during the same hour the system is peaking, they are not contributing marginal load to the system and thus not driving marginal capacity costs. Further, once a customer establishes their peak demand for a month, the sizable

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[110] Bachmeier Rebuttal at 25.

[111] For example, producing another MWh of energy from an existing plant may cost tens of dollars, while building a new power plant to produce another MW of capacity may cost tens or hundreds of millions of dollars.

portion of their bill based on the demand charge is locked in. Although the TOU energy rates on the RESDT rate continue to provide some incentive to minimize on-peak energy use after setting this peak, no such incentive exists for the RESD rate.

This is why a well-structured TOU rate that has a high peak/off peak ratio – such as our R-TECH proposal – is better than demand-based rates. By shifting the revenue collected from the demand component into a volumetric TOU rate with a 3:2:1 set of peak ratios, customers will have incentives throughout the month and year to reduce their on-peak usage. Of course, this would require the Company to expand TOU pricing to the base rates as well as the power supply rates, as I and other parties have advocated.

Q54. DO YOU HAVE AN EXAMPLE WHEN REWARDING HIGH LOAD FACTORS FOR INDIVIDUAL CUSTOMERS CAN BE COUNTERPRODUCTIVE?

A54. Yes. I took the average residential class hourly load profile for March (a month with ample spare capacity on the system and low energy costs) and June (which contained the peak load during the test year and higher energy costs). I then "filled up" all TOU peak hours by increasing the hourly load to the maximum level on-peak demand attained during in that month.

This adjustment has the effect of increasing the on-peak energy usage without increasing the peak billing demand, which in turn leads to a higher load factor. The resulting monthly load profiles are shown below in Figure 6. The blue lines represent June load, with the adjusted load showing the usage in the dashed line during the late afternoon peak period. The orange lines trace March load, showing the increased adjusted morning and evening peak usage, also in the dashed line..[112] The peak usage for the month is shown for reference by the horizontal dotted line.

[112] The adjusted load does not fully reach the monthly peaks as I only increased on-peak loads during weekdays; these same hours on weekends are off peak and were not adjusted.

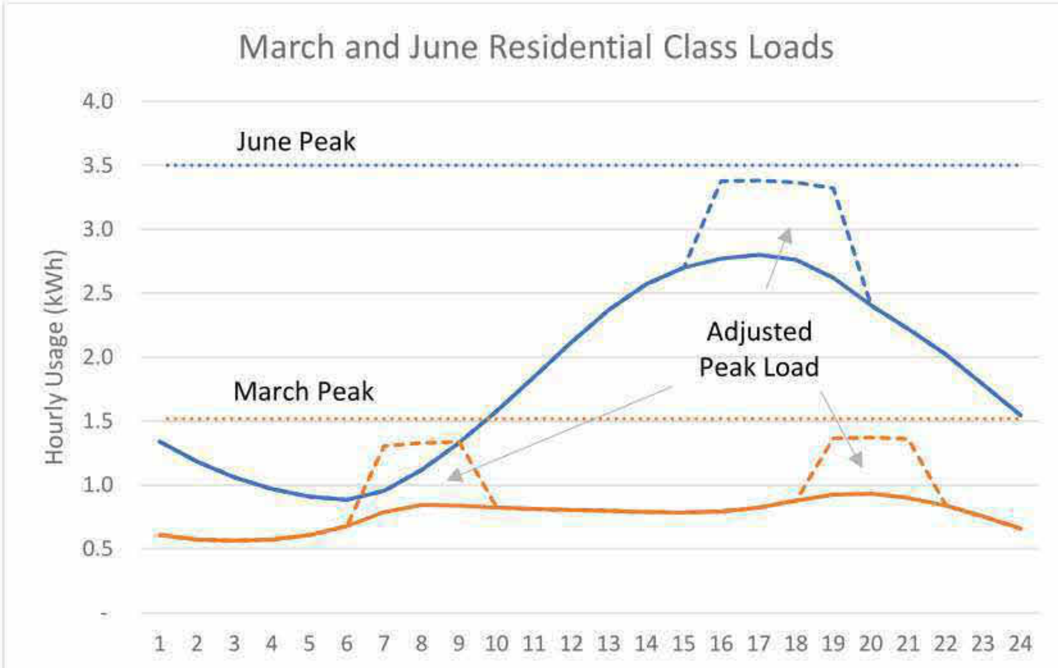

Figure 6 - March and June Residential Class Loads

The load metrics for these hypothetical customers are shown below in Table 3, with the load factors calculated based on the monthly or annual peak demand, which occurred in June. March peak usage increased to 209 kWh from 121 kWh, a 73% increase. June peak usage increased to 308 kWh from 233, a 32% increase. Total usage increased 16% and 6% in March and June, respectively. Mathematically, given that I held peak demand constant, the load factor also increased by several percentage points in both months.

	Peak	% Peak	Total	Demand	Monthly Load Factor	Annual Load Factor
March	121	21.3%	569	1.52	50.8%	21.9%
March Adj	209	31.8%	658	1.52	58.3%	25.2%
June	233	17.7%	1,316	3.50	52.2%	52.2%
June Adj	308	22.2%	1,391	3.50	55.2%	55.2%

Table 3 - March and June Residential Class Characteristics

Q55. DID YOU CALCULATE THE BILLS OF THESE USAGE PATTERNS?

A55. Yes, I did. The results are shown below in Figure 7, with each month indexed to the baseline bill for the unadjusted load profile in the respective month. As could be anticipated from the discussion above, bills for the unadjusted profile were slightly lower on the REST rate and significantly lower for the two demand-based rates. When the load profile was adjusted, the bill increased on both the RES and REST rates (as expected given the increase in both peak and total energy), while it continued to fall on the demand-based rates.

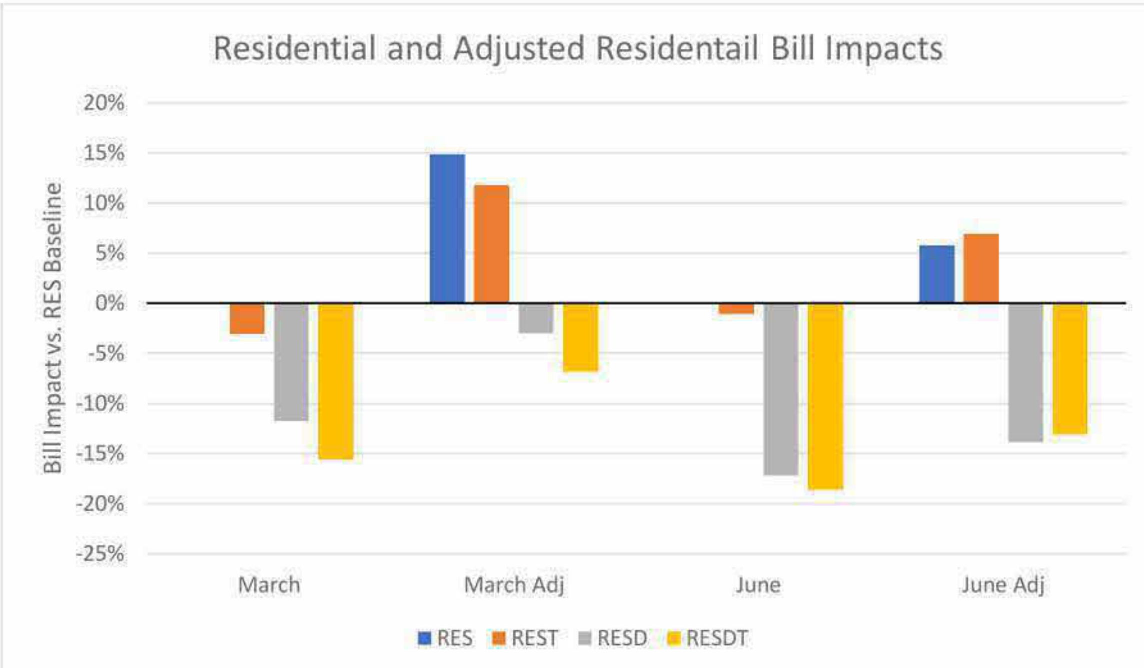

Figure 7 - Residential and Adjusted Residential Bill Impacts

Q56. WHAT DO THESE RESULTS DEMONSTRATE?

A56. They clearly demonstrate that the Company's demand-based rates improperly reward customers for high load factors above other considerations. In March, despite peak usage increasing by nearly 75% and total load increasing by 15%, the adjusted bill on the demand rates were lower than the baseline profile bill on the RES tariff. The difference was even larger in June, with the higher peak usage profile saving 13% compared to the baseline profile despite using more energy during the afternoon peak window. It is difficult to argue with a straight face that the adjusted load profiles are less costly to serve, but that is exactly the signal the demand-based rates are sending.

Q57. DID YOU FIND ANY EVIDENCE IN THE CUSTOMER DATA THAT DEMAND-BASED RATES ENCOURAGE LOWER ON-PEAK USAGE?

A57. No, I did not. Figure 8 below presents the bill impact as a function of on-peak; there exists no compelling relationship between savings on the two demand rates (orange and grey), while a clear indication of savings emerged as peak usage fell (blue). Clearly, peak usage is not the primary determinant of bill savings on the demand rates. Instead, customers with high load factors saved money whether they used more or less on-peak energy, while those with low load factors spend more money more or less independently of their on-peak usage. Consequently, it is inaccurate to suggest that these tariffs send a robust signal to reduce peak usage as Mr. Bachmeier suggests.

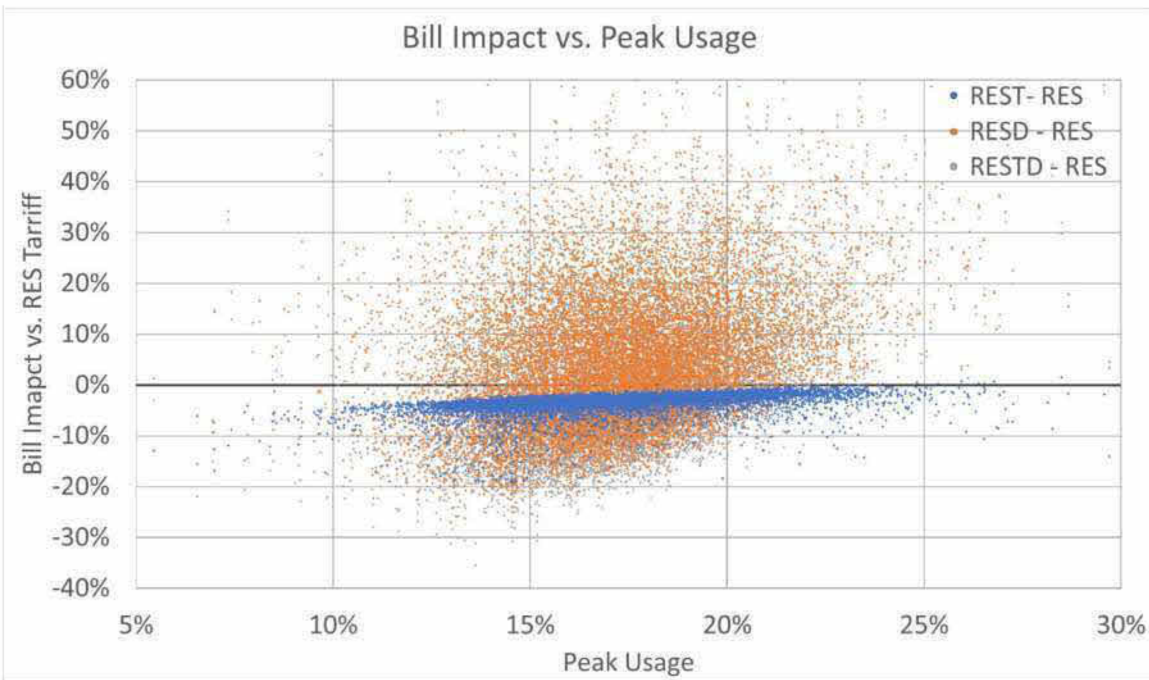

Figure 8 - Bill Impact vs. Peak Usage

Q58. WHAT IS YOUR CONCLUSION REGARDING TEP'S REBUTTAL ABOUT DEMAND-BASED RATES?

A58. TEP's observation that demand-based rates reward high load factors is accurate, as is my argument that high-use customers save money. However, the Company's conclusion that customers with high load factors produce system benefits or that the demand-based rates provide a price signal to reduce on-peak usage are both demonstrably false.

High load factors are desirable in aggregate, whether for an entire customer class or the system as a whole. But this relationship does not scale down to the level of individual customers. I was able to create a simple example showing that increasing load factors does not correspond to system cost reductions even while it affords those customers bill savings. In fact, customers who increased their on-peak usage while holding demand constant were able to get lower bills on the demand-based rates than a customer who did not increase their usage at all.

TEP's billing demand measurements, while limited to peak TOU periods, still do not clearly reflect cost-causation. Almost all individual customer peak demand occurrences are inframarginal and do not contribute to marginal system costs. More simply, peak demand in winter and shoulder months do not drive capacity needs, and most customers will hit their peaks outside the specific few hours where system loads are at their absolute peaks that do drive system costs.

By contrast, the TOU rate – even the weak one proposed by TEP – produced results consistent with expectations. Customers who used more energy during peak periods paid more, and customers that used less during peak periods paid less. The REST tariff provided a reliable price signal that reducing peak usage will reduce bills, and the Commission should approve the modifications that I and others proposed to strengthen the TOU rates to drive deeper system savings.

Q59. WHAT DO YOU RECOMMEND WITH REGARD TO THE COMPANY'S DEMAND-BASED RATES.

A59. As before, I recommend they be discontinued for new customers. Incenting high load factors does not necessarily lead to system cost reductions. Instead, the Commission should direct TEP to implement more robust TOU rates that provide more accurate and actionable price signals to reduce on-peak usage and provide actual benefits to all customers.

Q60. DOES THIS CONCLUDE YOUR TESTIMONY?

A60. Yes, it does.

EXHIBIT KL-20

TUCSON ELECTRIC POWER COMPANY'S 1st SUPPLEMENTAL RESPONSE TO ARISEIA'S THIRD SET OF DATA REQUESTS
2022 TUCSON ELECTRIC POWER RATE CASE
DOCKET NO. E-01933A-22-0107
February 17, 2023

ARISEIA 3.4

How much battery energy storage does the company plan to integrate into its system over the next five, ten, fifteen, and twenty years? How much of this battery energy storage will be: 1) utility-owned; 2) third-party owned but procured for or by the company; 3) or customer owned. For each of items 1 and 2, please include the projected all-in lifetime cost to ratepayers of the procurement, installation, operation, maintenance, financing, and all other costs passed to ratepayers including the utility's return on investment.

RESPONSE: ORIGINAL RESPONSE DATE December 22, 2022

Based on the 2020 TEP Integrated Resource Plan (IRP), the Company has projected the need for approximately 1,400 MW of energy storage by 2035. The Company is currently in the process of updating its resource plans based on updated planning assumptions and will file its 2023 IRP in August 2023. The exact composition of Company or third-party owned storage projects will be determined through future All-Source Requests for Proposals.

RESPONDENT:

Michael Sheehan

WITNESS:

Erik Bakken

SUPPLEMENTAL RESPONSE: February 17, 2023

The Company's last portfolio evaluation that included an analysis of energy storage technologies was done as part of the 2020 Integrated Resource Plan.[1] As noted in ARISEIA 3.4, TEP's 2020 Preferred IRP Plan calls for 1,400 MW of new energy storage technologies by 2035. TEP's preferred plan Portfolio ID: P17aL1M1E1 as shown on the Company's 2020 IRP Portfolio Dashboard summarizes the energy storage resource capacity installed by year.[2] Table 1 below provides the levelized cost of the new storage projects from 2024 through 2035. The Company's IRP makes no assumptions on whether a project is owned by a third-party[3] or by the utility[4]. The Company plans to file a new resource plan along with more up to date energy storage cost assumptions in its 2023 IRP on August 1, 2023.

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[1] https://docs.tep.com/wp-content/uploads/TEP-2020-Integrated-Resource-Plan-Lo-Res.pdf
See the Forward and Executive Summary on Pages 15 - 17 of the 2020 IRP.

[2] https://docs.tep.com/wp-content/uploads/Portfolios_Dashboards.pdf

[3] Including customer-owned facilities.

[4] The Integrated Resource Planning and Procurement rules do not require this type of analysis to be included the IRP plans.

TUCSON ELECTRIC POWER COMPANY'S 1st SUPPLEMENTAL RESPONSE TO ARISEIA'S THIRD SET OF DATA REQUESTS
2022 TUCSON ELECTRIC POWER RATE CASE
DOCKET NO. E-01933A-22-0107
February 17, 2023

Table 1 – 2020 IRP Energy Storage Costs by Year

4 Hour - Energy Storage Technology	
Levelized Cost	$/kW-Year
2024	$ 202.12
2028	$ 183.41
2030	$ 173.77
2032	$ 170.17
2034	$ 166.64

RESPONDENT:

Michael Sheehan

WITNESS:

Erik Bakken

EXHIBIT KL-21

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO ARISEIA'S TENTH SET OF DATA REQUESTS 2022 TUCSON ELECTRIC POWER RATE CASE DOCKET NO. E-01933A-22-0107 February 17, 2023

ARISEIA 10.01

Please refer to the company's responses to ARISEIA 6.03, 6.04, 9.01, and 9.03:

a. Please confirm that the Company agrees with each of these statements. If it does not, please provide a clarifying correction and any documents required to support its position.

   1. The DG meter charge is not intended to recover any portion of the cost of the production meter. (ARISEIA 9.01.j)

   2. Every non-DG, non-opt-out meter installed since 2020 has been bidirectional capable. (ARISEIA 9.01.k.ii)

   3. The "standard meter" used to calculate the DG Meter Fee is no longer being installed by the Company. (ARISEIA 9.012.i.ii)

   4. There is no incremental installation cost of a "household" meter installed for DG customers. (ARISEIA 9.01.m)

b. Confirm that the DG Meter Fee is charging new DG customers for incremental installation costs for "household" meters that no longer exist.

   1. If deny, please explain and reconcile with the answers provided above and in ARISEIA 9.01.

   2. If deny, please provide a detailed workpaper that includes all incremental installation costs for "household" meters that utilizes the Company's current meter make and model, labor hours, and labor rates, specifying all steps (e.g. meter configuration, meter testing, etc.) that are performed for DG "household" meters and for non-DG "household" meters.

c. The Company states in ARISEIA 9.01.m that "there is an incremental installation cost associated with the bidirectional DG production meter."

   1. Is the DG Meter Fee recovering the incremental installation cost associated with the bidirectional production meter?

   2. If the answer to 1 above is yes, please reconcile this with the Company's statements and Commission Orders 75975 and 76899.

   3. If the answer to 1 above is no, what costs is the DG Meter Fee recovering?

   4. What is the incremental installation cost relative to?

   5. Please provide a worksheet that details the incremental installation costs associated with the bidirectional DG production meter. Specify equipment cost, labor rate, and labor hours by specific task (e.g., configure meter, test meter, etc.), at a minimum, in addition to other data needed to fully identify the incremental installation cost of a bidirectional DG production meters compared to a non-bidirectional DG production meter or non-DG bidirectional meter.

   6. What make and model would the Company install as a DG production meter that is not bidirectional? When was the last month the Company installed this specific meter?

d. Please provide the number of residential and small commercial DG systems installed by month starting in January 2018 to the most current month of data.

e. How many DG customers are currently being charged a DG Meter Fee?

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO ARISEIA'S TENTH SET OF DATA REQUESTS 2022 TUCSON ELECTRIC POWER RATE CASE DOCKET NO. E-01933A-22-0107 February 17, 2023

f. Please provide the total revenue collected through the DG Meter Fee monthly from September 2018 to the latest month available, broken down by residential and small commercial customers.

g. Confirm that the Company installed roughly 3,000 to 4,000 residential non-bidirectional AMR meters in the time between the Commission's September 2018 Order 76899, and the January 2019 approval of its full AMI meter rollout, according to ARISEIA 9.03j. If deny, please provide the figure of residential, non-bidirectional meters installed between Order 76899 and approval of the Company's full AMI rollout.

h. Regarding the Company's AMI rollout

   1. When did the Company know that the AMI meters it was going to use would have bidirectional reading capability?

   2. When was the final selection of the specific make and model of AMI meter made?

RESPONSE:

a. 1-3 - Confirmed. 4 – there is no incremental installation cost for installing an AMI (or "household") meter for DG customers.

b. Confirmed.

c. 1-6 It appears there is a misunderstanding regarding the interpretation of TEP's response to ARISEIA 9.01m. The question asked if there was "an incremental cost associated with bidirectional meters" for DG customers. While there is not an incremental cost difference between the different types of bidirectional household meters installed for DG, there is still an incremental cost association, the association referring to the presence of a second bidirectional meter. The Company is not aware of any time when it installed non-bidirectional non-billing meters for DG.

d. Please see ARISEIA 10d Monthly Install Breakdown.xlsx.

e. As of December 2022, there are 25,236 customers being charged the DG Meter Fee.

f. Please see ARISEIA 10f DG Meter Fee Collection.xlsx.

g. Confirmed.

h. 1-2 TEP did not make a final determination on the meters, capabilities, and final deployment strategy to transition to AMI until the Company completed its initial pilot project in December of 2018. The approval to move forward with AMI was January 2019.

Excel files are <u>not</u> identified by Bates numbers.

RESPONDENT:

Jared Dang/Frank Mendez/Sam Molina/Chris Fleenor

WITNESS:

Jared Dang (10.01 a1,a4, b, c, e, f) / Cynthia Garcia (10.01 a2-3,d,g,h)

EXHIBIT KL-22

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO ARISEIA'S NINTH SET OF DATA REQUESTS 2022 TUCSON ELECTRIC POWER RATE CASE DOCKET NO. E-01933A-22-0107 February 3, 2023

ARISEIA 9.03

Please refer to the Company's response to ARISEIA 6.04 and workpaper ARISEIA 6.04f:

a. What was the specific reason(s) that labor costs in the workpaper for the residential bidirectional meter were substantially higher than for a residential standard meter?

b. Please provide the labor hours associated with each meter installation in the workpaper.

c. Please provide the labor rate associated with each meter installation in the workpaper.

d. If the assumed labor hours associated with the bidirectional meter are higher than for a standard meter, please explain in detail why this is the case.

e. If the assumed labor rate associated with the bidirectional meter is higher than for a standard meter, please explain in detail why this is the case.

f. When did the Company begin planning for its AMI meter rollout?

g. When did the Company get approval for its AMI meter rollout?

h. When did the Company begin installing AMI meters?

i. Confirm that the Company's AMI meters installed for non-opt out customers are all capable of bidirectional measurement. If deny, please explain and provide the makes, models, and counts of AMI meters installed that cannot perform bidirectional measurement.

j. Please provide a count of residential AMR and AMI meters installed by month since January 2015.

RESPONSE:

a. The specific reason was because of the additional labor hours associated with configuring the bidirectional meter.

b. Please see ARISEIA 9.04. The Company has attached the data request response but could not find the source calculation where the labor hours and labor rate assumptions between the technician and communication specialist workpapers were made.

c. Please see ARISEIA 9.04. The Company has attached the data request response but could not find the source calculation where the labor hours and labor rate assumptions between the technician and communication specialist workpapers were made.

d. Please see ARISEIA 9.04a.

e. Labor rates were the same.

f-h. The Company first contemplated a potential transition to AMI in January of 2016. To test AMI's capability, the Company started an AMI Pilot program in May of 2018. The results of the pilot and "Drop In Network" were ready in December of 2018 and were used to make the "Go/No-Go" decision. Full AMI meter deployment was approved in January 2019 and began in January 2019.

i. Please see ARISEIA 9.01l.

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO ARISEIA'S NINTH SET OF DATA REQUESTS 2022 TUCSON ELECTRIC POWER RATE CASE DOCKET NO. E-01933A-22-0107 February 3, 2023

j.

2015	
Month & Meter Type	Total installs by type
Jan	
AMR	12172
Feb	
AMR	12530
Mar	
AMR	11834
Apr	
AMR	11710
May	
AMR	11737
Jun	
AMR	11310
Jul	
AMR	9292
Aug	
AMR	9270
Sep	
AMR	5747
Oct	
AMR	6040
Nov	
AMR	3635
Dec	
AMR	3493

2016	
Month & Meter Type	Total installs by type
Jan	
AMR	1432
Feb	
AMR	1901
Mar	
AMR	2101
Apr	
AMR	1630
May	
AMR	2283
Jun	
AMR	2059
Jul	
AMR	1664
Aug	
AMR	2359
Sep	
AMR	2195
Oct	
AMR	2076
Nov	
AMR	1991
Dec	
AMR	1829

2017	
Month & Meter Type	Total installs by type
Jan	
AMR	1469
Feb	
AMR	1575
Mar	
AMR	2394
Apr	
AMR	2068
May	
AMR	1890
Jun	
AMR	2008
Jul	
AMR	1387
Aug	
AMR	1525
Sep	
AMR	969
Oct	
AMR	1349
Nov	
AMR	1175
Dec	
AMR	1023

2018	
Month & Meter Type	Total installs by type
Jan	
AMR	986
Feb	
AMR	879
Mar	
AMR	1294
Apr	
AMR	948
May	
AMR	1260
Jun	
AMR	1358
AMI	136
Jul	
AMR	1439
Aug	
AMR	1395
AMI	1550
Sep	
AMR	1279
AMI	10
Oct	
AMR	1215
AMI	1508
Nov	
AMR	1192
AMI	1387
Dec	
AMR	306
AMI	3324

2019	
Month & Meter Type	Total installs by type
Jan	
AMR	77
AMI	8616
Feb	
AMR	3
AMI	9937
Mar	
AMI	10144
Apr	
AMI	11884
May	
AMI	7901
Jun	
AMR	1
AMI	7973
Jul	
AMR	1
AMI	8699
Aug	
AMI	8266
Sep	
AMI	9388
Oct	
AMI	11597
Nov	
AMI	9073
Dec	
AMI	9645

2020	
Month & Meter Type	Total installs by type
Jan	
AMI	10683
Feb	
AMI	9283
Mar	
AMI	10386
Apr	
AMI	4060
May	
AMI	1504
Jun	
AMI	1879
Jul	
AMI	2226
Aug	
AMI	2006
Sep	
AMI	1974
Oct	
AMI	3735
Nov	
AMI	6563
Dec	
AMI	8243

2021	
Month & Meter Type	Total installs by type
Jan	
AMI	10407
Feb	
AMI	11981
Mar	
AMI	11448
Apr	
AMI	8448
May	
AMI	7348
Jun	
AMI	6836
Jul	
AMI	6871
Aug	
AMI	6732
Sep	
AMI	6040
Oct	
AMI	5840
Nov	
AMI	4979
Dec	
AMI	4190

2022	
Month & Meter Type	Total installs by type
Jan	
AMI	5113
Feb	
AMI	5575
Mar	
AMI	6521
Apr	
AMI	5638
May	
AMI	5053
Jun	
AMI	5133
Jul	
AMI	4113
Aug	
AMI	5259
Sep	
AMI	6270
Oct	
AMI	4811
Nov	
AMI	4454
Dec	
AMI	5200

RESPONDENT:

Frank Mendez / Jared Dang

WITNESS:

Cynthia Garcia

EXHIBIT KL-23

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO ARISEIA'S THIRTEENTH SET OF DATA REQUESTS 2022 TUCSON ELECTRIC POWER RATE CASE DOCKET NO. E-01933A-22-0107 March 3, 2023

ARISEIA 13.01

Please refer to the Company's response to ARISEIA 10. Regarding the Company's AMI meter pilot:

a. When did the pilot officially kick off?

b. Was there any discussion or consideration of using AMI meters that did not have bidirectional reading capability? If so,

   i. What makes and models of non-bidirectional meters were considered?

   ii. At what point was a decision made to pilot bidirectional meters?

   iii. At what point was a preliminary decision made to use bidirectional meters if and when the pilot was approved?

c. Did the Company install any non-bidirectional AMI meters during the pilot? If so, please provide a count of such meters installed by month.

RESPONSE:

a. The pilot started in May of 2018.

b. The Company does not recall any discussion or consideration to use AMI meters that did not have bidirectional capability.

c. No, non-bidirectional AMI meters were not installed during the pilot.

RESPONDENT:

Chris Fleenor

WITNESS:

Cynthia Garcia

EXHIBIT KL-24

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO ARISEIA'S THIRTEENTH SET OF DATA REQUESTS 2022 TUCSON ELECTRIC POWER RATE CASE DOCKET NO. E-01933A-22-0107 March 3, 2023

ARISEIA 13.02

Please refer to the Company's response to ARISEIA 10 and the rebuttal testimony of Jared. C. Dang at page 7, lines 19-24, which states: "The fee was originally based upon information that showed a significant cost difference between a cheaper AMR meter installation applicable to billing non-DG customers and the more expensive AMR bidirectional meter installation that was necessary for billing DG customers. However, over time the Company has moved towards utilizing the same bidirectional AMI meter for DG and non-DG customers, therefore there is no longer a basis for the fee."

a. Please provide specific dates that define the timeframe referenced in bold in the statement "However, over time, the Company…" That is, provide the specific time after the fee was established when the Company stopped installing non-AMI AMR meters for non-DG customers and instead installed the same bidirectional AMI meter for DG and non-DG customers.

b. Did the Company ever install a non-bidirectional AMI household meter for DG customers? If so, please provide a count of such meters installed by month.

RESPONSE:

a. Please refer to 13.01a for the pilot start date. Please see 10.01h for the pilot end date. The AMI move forward decision date was January 2019.

b. No.

RESPONDENT:

Chris Fleenor

WITNESS:

Cynthia Garcia

EXHIBIT KL-25

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO ARISEIA'S TWELFTH SET OF DATA REQUESTS 2022 TUCSON ELECTRIC POWER RATE CASE DOCKET NO. E-01933A-22-0107 February 28, 2023

ARISEIA 12.01

Please refer to Jared C. Dang rebuttal at pages 7-8. When the Company states that it "will eliminate the DG Incremental Meter Fee on a going forward basis," does this apply to both existing DG customers that have been paying the DG Incremental Meter Fee and new DG customers? If not, please explain.

RESPONSE:

This will apply to both existing DG customers and new DG customers at the new base rate effective date.

RESPONDENT:

Jared Dang

WITNESS:

Jared Dang

EXHIBIT KL-26

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO ARISEIA'S THIRTEENTH SET OF DATA REQUESTS 2022 TUCSON ELECTRIC POWER RATE CASE DOCKET NO. E-01933A-22-0107 March 3, 2023

ARISEIA 13.03

Please refer to the Company's response to ARISEIA 10 and the rebuttal testimony of Jared. C. Dang at page 8, lines 1-5, which states:, "Q. Should the Company credit back the costs associated with the DG Incremental Meter Fee as discussed by Mr. Lucas? A. No. The DG Incremental Meter Fee was created in a Commission decision. Like other service fees that change or are eventually discontinued, this change should be made on a going forward basis upon Commission approval."

a. Are the Company's fees on the Statement of Charges required to be cost-based? If not, please indicate which fees are not cost based and what the fee is based on.

b. Are there other fees on the Company's Statement of Charges where the underlying cost on which the fee was based has fallen or been reduced since the fee was last approved? If so, please provide the updated cost of the fee.

c. Does the Company regularly analyze its Statement of Charges to see if the underlying fees no longer match up with underlying costs on which the fee is based? If so, please describe the process. If not, please explain why not.

d. Does the Company have any obligation to inform the Commission that one of its fees is based on outdated information?

e. Has the Company in the past informed the Commission that one of its fees is too low and should be increased?

f. Based on workpaper ARISEIA 10f, the Company has collected over $1.5 million in DG Meter fees for a cost that the Company admits does not exist. Residential customers who have been charged this fee since the AMI program was approved in early 2019 have been charged more than $100 for costs that never existed for them. Why it is appropriate for the Company not to refund these customers for these fees?

RESPONSE:

a. There is a cost basis for all the Company's service fees at the time the fees were approved by the Commission.

b. Please see the redline Exhibit JCD-1 (PDF page 26) in the Direct Testimony of Jared Dang to see the Service Fees and the resulting price changes. Service Fee 1, 2, 4, 5, 6, 7, 8, 9, 10 and 15 reflect lower prices.

c. The Company reviews the Statement of Charges during the rate case process. The Company reviews the underlying cost structure the fees are based on and modifies the price if needed.

d. The Company is not aware of any specific obligation to notify the ACC if one of its fees is based on outdated information.

e. Please see response to 13.03b. Service Fee 12, 13 and 17 are proposed to be increased.

f. The Company objects to the extent this request seeks a legal opinion. Notwithstanding that objection in Arizona, rates and charges are set based on a historical test year. The fee was based on a Commission decision which was made utilizing the best information at that time. Like any other service fee and rate changes, this change should be made on a going forward basis upon Commission approval.

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO ARISEIA'S THIRTEENTH SET OF DATA REQUESTS 2022 TUCSON ELECTRIC POWER RATE CASE DOCKET NO. E-01933A-22-0107 March 3, 2023

RESPONDENT/WITNESS:

Jared Dang

EXHIBIT KL-27

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO ARISEIA'S TWELFTH SET OF DATA REQUESTS 2022 TUCSON ELECTRIC POWER RATE CASE DOCKET NO. E-01933A-22-0107 February 28, 2023

ARISEIA 12.02

Please refer to Richard D. Bachmeier rebuttal at page 18.

a. Does the Company separately account for Margin and Base revenues throughout its financial statements, or are these revenues combined when reporting total revenues?

b. Does the Company have a revenue decoupling mechanism that treats Margin and Base revenues differently? If so, please discuss the differences.

c. What percentage of total residential revenues come from customers on TOU tariffs?

d. What percentage of margin revenues comes from customers on TOU tariffs?

e. Would the Company be opposed to creating a new TOU rate that expands TOU pricing to margin revenues while leaving existing TOU rates in place? If not, please explain.

RESPONSE:

a. "Financial statements" is a vague reference and could include various reports. Taking the Company's 10-K report as an example, Fuel and Purchased Power is broken out separately in the Consolidated Statements of Income, but Revenues are also presented with the Margin and Fuel and Purchased Power elements combined.

b. The Company has no revenue decoupling mechanism. Fuel and Purchased Power revenues collected through Base Power and PPFAC charges are recorded and compared to actual Fuel and Purchased Power expenses to calculate over- or under-recovery.

c. In the test year (unadjusted), approximately 8.1% of total residential revenues were collected from customers on TOU rate plans.

d. In the test year (unadjusted), approximately 8.3% of residential margin revenues were collected from customers on TOU rate plans.

f. Yes, the Company would be opposed.

RESPONDENT:

Richard Bachmeier

WITNESS:

Richard Bachmeier

EXHIBIT KL-28

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO ARISEIA'S TWELFTH SET OF DATA REQUESTS 2022 TUCSON ELECTRIC POWER RATE CASE DOCKET NO. E-01933A-22-0107 February 28, 2023

ARISEIA 12.03

Please refer to Richard D. Bachmeier rebuttal at page 24, which states "I assume that these 8,300 or so residential customers understand the difference between energy and demand and prefer service on a demand rate."

a. Does Mr. Bachmeier have any support for this assumption, such as customer surveys regarding demand-based rates? If so, please provide them.

b. Has TEP at any time offered customers advice on which tariff best suits their usage patterns, either through an online tool or through a customer service representative? If so, please provide a description of these services.

RESPONSE:

a. TEP has no customer surveys on this issue. Mr. Bachmeier's support for the statement is the assumption in Economic Theory that consumers are rational economic agents.

b. TEP has a Pricing Planner tool on the Company's website to assist residential customers with finding the rate plan that best suits their lifestyle and usage patterns. The web address for TEP's Pricing Planner is https://www.tep.com/compare-pricing-plans/.

RESPONDENT:

Richard Bachmeier

WITNESS:

Richard Bachmeier

EXHIBIT KL-29

TUCSON ELECTRIC POWER COMPANY'S 1st SUPPLEMENTAL RESPONSE TO ARISEIA'S EIGHTH SET OF DATA REQUESTS 2022 TUCSON ELECTRIC POWER RATE CASE DOCKET NO. E-01933A-22-0107 February 1, 2023

ARISEIA 8.01

Please refer to 2021 TEP Schedule H-4.xlsx:

a. Please provide 2021 8760 load data for 5 customers that take service on the TILGST tariff that most closely approximate the annual kWh usage of each the five listed tiers (e.g., 1 customer who uses approximately 110,655 kWh per year to correspond to the Xsm category, etc). Please remove any identifiable information of the customer.

b. What is the source of the Load Factor values used to calculate billing demand in tariffs with a demand charge?

c. Why does the Company assume that the load factor for all sample customers in a commercial tariff (e.g. TILGS) remains constant within a given tariff as energy usage increases? Is this assumption supported by actual billing data from actual customers on the tariff?

d. Please provide all workpapers that were used to calculate the demand rate load factor parameters for residential customers and small general service customers.

ORIGINAL RESPONSE: January 30, 2023

a. Please see ARISEIA 8.01a 5 LGST Load Profiles.xlsx.

b. There is no source behind the load factor values for the Medium General Service through 138kV customer class sizes. For residential and small general service rates, please see ARISEIA 8.01b SGS.xlsx and ARISEIA 8.01b RES.xlsx.

c. The Company does not assume that the load factor for all sample customers in a commercial tariff (e.g. TILGS) remains constant within a given tariff as energy usage increases. The Company used a constant load factor across different usage sizes in the Medium – General Service through 138kV customer classes for the purposes of Schedule H-4 presentation.

d. See response to 8.01b.

The Excel files are <u>not</u> identified by Bates numbers.

RESPONDENT:

Jared Dang

WITNESS:

Richard Bachmeier

SUPPLEMENTAL RESPONSE: February 1, 2023

a. Please see ARISEIA 8.01 TEP RES Load Data.xlsx.

RESPONDENT:

Jared Dang

WITNESS:

Richard Bachmeier